Renewable and Sustainable Energy Reviews 16 (2012) 6083–6102

Contents lists available at SciVerse ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

Performance of simulated flexible integrated gasification polygeneration facilities, Part B: Economic evaluation.

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ARTICLE INFO

Article history:
Received 18 November 2011
Received in revised form
26 June 2012
Accepted 27 June 2012
Available online 16 August 2012

Keywords:
Economic assessment
Gasification
Flexibility
Refinery
Biofuels
Biochemicals

ABSTRACT

This paper investigates the economics of integrated gasification polygeneration (IG-PG) facilities and assesses under which market conditions flexible facilities outperform static facilities. In this study, the facilities use Eucalyptus wood pellets (EP), torrefied wood pellets (TOPS) and Illinois #6 coal as feedstock to produce electricity, FT-liquids, methanol and urea. All facilities incorporate CCS. The findings show production costs from static IG-PG facilities ranging between 12 and 21 €/GJ using coal, 19–33 €/GJ using TOPS and 22–38 €/GJ using EP, which is above the average market prices. IG-PG facilities can become competitive if capital costs drop by 10%–27% for coal based facilities. Biomass based facilities will need lower biomass pellet prices or higher CO_2 credit prices. Biomass becomes competitive with coal at a CO_2 credit price of 50–55 €/t CO_2. Variations in feedstock, CO_2 credit and electricity prices can be offset by operating a feedstock flexible IG-PG facility, which can switch between coal and TOPS, thereby altering its electricity production. The additional investment is around 0.5% of the capital costs of a dedicated coal based IG-PG facility. At 30 €/t CO_2, TOPS will be the preferred feedstock for 95% of the time at a feedstock price of 5.7 €/GJ. At these conditions, FT-liquids (gasoline/diesel) can be produced for 15.8 €/GJ (116 $/bbl). Historic records show price variations between 5.7 and 7.3 €/GJ for biomass pellet, 1.0–5.6 €/GJ for coal and 0–32 €/t CO_2. Within these price ranges, coal is generally the preferred feedstock, but occasionally biomass is preferred. Lower biomass prices will increase the frequency of switching feedstock preference from coal to biomass, raising the desire for flexibility. Of the three investigated chemicals, an IG-PG facility producing FT-liquids benefits the most from flexibility. Our study suggests that if the uncertainty in commodity prices is high, a small additional investment can make flexible IG-PG facilities attractive.

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Contents

Abbreviations: AGR, acid gas removal; a.r., as received; ARA, Amsterdam–Rotterdam–Antwerp; ASU, air separation unit; CCS, carbon capture and storage; d.a.f., dry, ash-free; EP, Eucalyptus pellets; FEP, feedstock equivalent price; FW, FosterWheeler; GT, gas turbine; HHV, higher heating value; HRSG, heat recovery steam generation; IEA GHG, International Energy Agency Greenhouse Gas R&D Programme; IGCC, integrated gasification combined cycle; IG-PG, integrated gasification polygeneration; LHV, lower heating value; LPMeOH^{TM}, liquid phase methanol synthesis process; NPV, net present value; PEP, electricity-chemical equivalent price; ppm, parts per million; PSA, pressure swing adsorption; SOTA, state-of-the-art; *t*, metric tonne; TCI, total capital investments; TOPS, torrefied (wood) pellets; WGS, water–gas shift; XtY facility, Facility that converts feedstock X to product Y

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http://dx.doi.org/10.1016/j.rser.2012.06.030

1. Introduction

A significant reduction of global CO_2 emissions will require decarbonisation of both the transport and power sector. State-of-the-art (SOTA) flexible integrated gasification poly-generation (IG-PG) facilities[1] equipped with CO_2 capture can potentially decarbonise both sectors and play a role in the development of a sustainable energy infrastructure. In the first place, they can produce CO_2 neutral transportation fuels. Secondly, they can act as back-up power plants. Thirdly, flexible IG-PG facilities can potentially offer attractive economics by responding to fluctuating market conditions, such as the daily variation in electricity price or the seasonal price variation in biomass pellet price.

Large scale IG-PG facilities are built to operate for several decades. During that time frame, market conditions can change considerably. This holds especially for the emerging markets of biomass pellets for energy [1,2], CO_2 credits [3] and non-oil based transportation fuels [4] as well as the mature markets of coal [5] and electricity [6]. In addition, in the coming decades shifts are likely to occur in the production and use of main transportation fuels, where gasoline and diesel could be replaced by methanol, hydrogen or electricity. Besides long-term uncertainties, there are also short-term variations which could have an impact on the profitability of IG-PG facilities. One example is the daily variation of the electricity price [6]. These uncertainties may make flexible IG-PG facilities valuable in the (future) development of a sustainable energy infrastructure.

Although the economics of IG-PG facilities have been extensively analysed [7–18], only a few studies have investigated the impact of flexibility on these facilities. Carapellucci et al. [19] for instance, investigated the technical and economic performance of flexible methanol/electricity production, while a study made by the IEA GHG investigated the technical and economic performance of flexible hydrogen/electricity production [7,8]. In a previous study [20], we investigated the technical performance and limitations of various processes in SOTA flexible IG-PG facilities. The investigated facilities use commercially available technologies only. The previous study focuses on the performance of individual components as well as the entire facility when feedstock or product mix is altered. This includes de-rating, overdimensioning of key components, like the gasifier, and minimal load constraints. Results show that, from a technical point of view, both feedstock and product flexibility are possible, although with certain limitations. For instance, the volume of the syngas exiting the gasifier remains constant, regardless of the used feedstock. Compared to coal, biomass produces more gas per energy input, resulting in a reduction in total energetic input when switching from coal to biomass. Overdimensioning the gasifier is possible but increases capital costs. The minimal load of important process equipment – e.g., chemical synthesis reactors, distillation columns and gas turbines – was found to be 40%. Also, co-feeding of biomass has been maximised at 50% on an energy basis.[2] In addition, the results indicated that part-load operation due to feedstock substitution hardly affects overall facility efficiency.

Compared to static[3] facilities, flexible facilities can respond to and exploit fluctuating market conditions, expectedly resulting in overall lower feedstock costs and higher product revenues. However, flexible facilities also have higher capital investment and O&M costs and, depending on operation mode, some efficiency losses (see Meerman et al. [20]). Currently, it is not known whether the advantages of flexibility offset its disadvantages, despite that flexibility is argued to be a strong argument in favour of IG-PG facilities.

The goal of the present study was to determine if, and under which economic conditions, flexible design and operation could lead to favourable economic performance of SOTA IG-PG facilities. This analysis focused on the use of Eucalyptus pellets (EP), torrefied wood pellets (TOPS) and Illinois #6 coal as potential feedstocks. The feedstocks were converted into electricity, FT-liquids, methanol and urea. To reduce CO_2 emissions, pre-combustion CO_2 capture technology was included in all cases. In this study it was assumed that the facilities begin operation in 2015. Therefore, only commercially available technologies were considered.

The structure of this article is as follows: Section 2 describes the methodology, including the technical component based AspenPlus model, the case studies where different aspects of flexibility are analysed, the scenarios represent different economic climates, and the component capital costs. In Section 3 the economic parameters are given. Section 4 contains the results. In section 5 the discussion as well as key conclusions are provided. In this study all units are in SI-units, heating values are expressed in higher heating value (HHV) and costs in €$_{2008}$, unless stated otherwise.

[1] In IG-PG facilities solid feedstocks are converted into synthesis gas and subsequently into electricity, chemicals or fuels. These facilities are referred to as XtY systems. The X is substituted if a specific feedstock is used: biomass (BtY), torrefied biomass (TtY) or coal (CtY). The Y is substituted if a specific output is produced: electricity (XtP), FT-liquids (XtL), methanol (XtM) or urea (XtU).

[2] This limitation results from the different ash and alkali composition and quantity in biomass compared to coal. At high biomass ratios, the different ash amount and composition causes, among other, reduction of the protective slag layer and fouling of heat exchangers.

[3] Static facilities have little to no ability to change their input or output. Feedstock must meet stringent specifications and production of fuels, chemicals or electricity cannot be altered.

2. Methodology

The required technical data of the facilities, like component dimensions, efficiencies and mass and energy balances, were derived from the technical assessment done in part A of this analysis [20]. It was assumed that the IG-PG facilities use SOTA technology and are operated between 2015 and 2035. The point of departure for the economic data used in this study was a study made by FosterWheeler [7] published in 2007 (see Section 3.2 for more details). The economic data were obtained using information from expert interviews and open literature sources and updated to €$_{2008}$. By combining the capital costs with current commodity prices, first production costs of electricity, FT-fuels, methanol and urea, produced by static IG-PG facilities, were calculated. Next, these production costs were compared with those of flexible IG-PG facilities. For this purpose, production costs of 6 different operating strategies (cases) in 5 different scenarios were assessed, taking into account capital costs data and – variation in – historical prices of coal, biomass pellet and CO_2 credits. A schematic overview of the methodology is displayed in Fig. 1. In the rest of this section an overview of each step is presented.

2.1. Technical data and AspenPlus process model

When the feedstock or product mix of an IG-PG facility is altered, mass and energy flows and efficiencies throughout the different components change. The components in a flexible IG-PG facility (Fig. 2) must be able to handle this and were therefore dimensioned to the largest possible required capacity. This, however, means that, at times, certain processes would operate under part-load conditions, resulting in de-rating and efficiency losses. These effects increase with decreasing load levels, up to a point where the component can no longer operate properly. A second effect is that the capital costs of components are higher than those of static facilities. To calculate the mass and energy flows and the required size of each component, a previous developed AspenPlus simulation model on a component level was used [20]. The most important assumptions and results of the model are given below. We refer to Meerman et al. [20] for further detailed information.

Key characteristics of the model are:

- Inclusion of three different types of feedstock: Illinois #6 coal, Eucalyptus wood pellets (EP) and torrefied wood pellets (TOPS);
- The IG-PG facility is based on a 2000 MW_{th} coal input-equivalent Shell gasifier. This means that, based on the model results, thermal input for 100% TOPS is 1696 MW_{th} and for 100% EP only 1464 MW_{th} [20]. When biomass is co-fed, the thermal input lays between these two extremes;
- Three different feedstock ratios: 100% coal, 50%/50% biomass/coal (on an energy basis) and 100% biomass; both for TOPS and EP. The 50 energy$_{HHV}$% biomass was considered the current technical maximum for co-feeding biomass in the gasifier [20]. Although 100% biomass input is currently technically not possible, this option was also assessed, to determine the effects on component size and overall plant efficiency and output;
- Four different outputs as main product: electricity, FT-liquids (gasoline/diesel), methanol and urea. When producing the chemicals or fuels as main product, electricity is produced as by-product. Not considered is the simultaneous production of two or more chemicals/fuels. Based on Meerman et al., the minimal load of the main processes, like the air separation unit, water–gas shift (WGS) reactor, chemical conversion reactors, gas and steam turbines, is 40% when considering production flexibility; [20].
- As all IG-PG facilities already separate CO_2 after gas cleaning, the only additional step for CO_2 capture is compression. However, since the H_2:CO ratio is kept constant at 2.3,[4] only 56% (for coal) to 65% (for EP) of the total carbon is captured (Fig. 3). In this study all investigated IG-PG configurations were assumed to operate with carbon capture and storage (CCS).

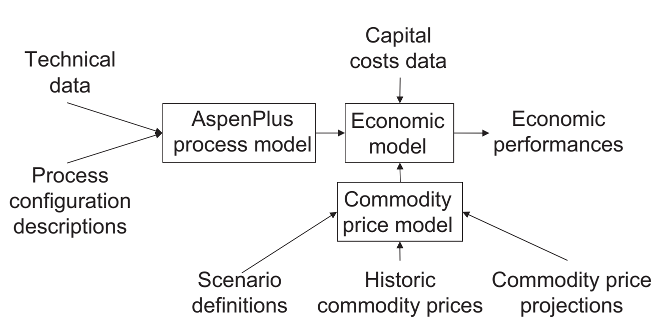

Fig. 1. Schematic overview of the methodological steps included in this study.

Plant efficiencies of static IG-PG facilities following from the model analysed in Meerman et al. [20] are shown in Table 1.

2.2. Case studies

In this article 6 cases were studied to provide insight into the economic performance of flexible IG-PG facilities. In all cases the technical model, described in part A of this analysis, was used [20].

Case 1. Static IG-PG facilities

This case study served as reference case. The static IG-PG facilities had fixed feedstock and production mixtures. All equipment was optimised to these characteristics. As a result, the facilities were almost non-flexible or would display strong de-rating impacts when operated at part-load conditions.

Case 2. Variation of feedstock: Capital costs penalty.

This case study served to investigate the increase in production costs when a feedstock flexible designed IG-PG facility is operated as if it is a static IG-PG facility by comparing the production costs with an IG-PG facility which is optimised for one feedstock only.

Case 3. Variation of feedstock: Constant chemical production and variable electricity production by feedstock substitution.

This case study was used to investigate under which economic conditions (feedstock and CO_2 credit prices) exploiting the fluctuations in electricity price by adjusting the feedstock biomass/coal ratio pays off. Using coal instead of biomass as feedstock leads to a larger energetic flow of the syngas[5] [20]. As the chemical production was kept constant, an increase in syngas energy results in an increase in electricity production. This additional electricity was sold at spot market prices [6]. Under the right economic conditions, this can lead to the use of biomass during off-peak hours and the use of coal during peak hours. To determine whether coal or biomass is the most economic option, a feedstock equivalent price (FEP, see Section 2.5) was used.

[4] This value was selected as it is the lowest H_2:CO ratio needed for the chemical section, resulting in less variation in the gas cleanup section [20].

[5] This is caused by the higher energy density of coal compared to biomass and the assumption that the gasifier has a fixed gas generation capacity. The thermal input of coal is 2000 MW_{th}. This drops to 1696 MW_{th} for TOPS and 1464 MW_{th} for EP.

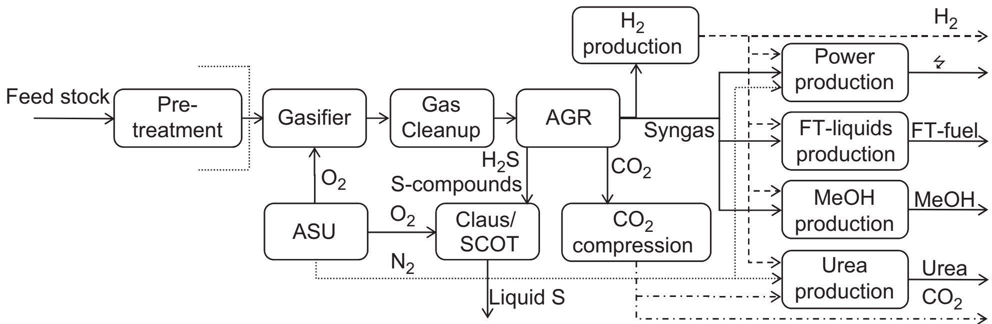

Fig. 2. Simplified layout of a flexible IG-PG facility process. Waste, energy and heat streams are not displayed [20].

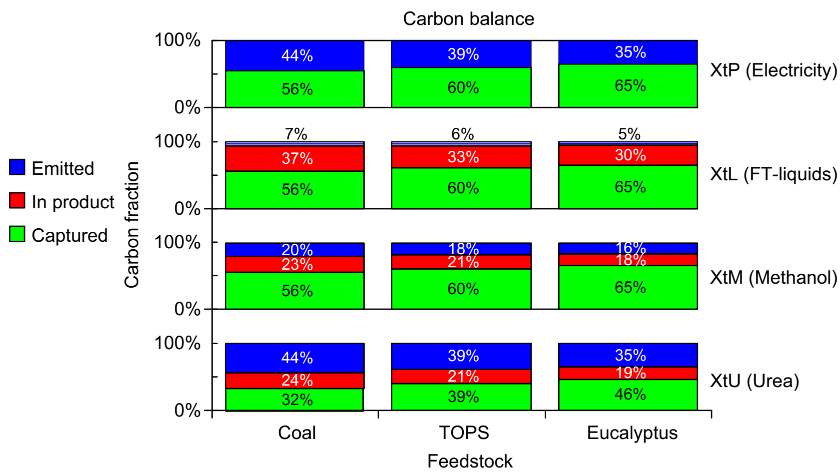

Fig. 3. Calculated carbon fractions as captured, emitted and embedded in chemical/fuel output [20].

Table 1
Overall energy efficiencies (HHV) of static XtY facilities.

Energy efficiency	Output	Coal (%)	TOPS (%)	EP (%)
Electricity (XtP)	**Power**	**40**	**39**	**38**
FT-Liquids (XtL)	FT	49	47	43
	Power	10	11	12
	Total	**60**	**58**	**55**
Methanol (XtM)	MeOH	33	31	29
	Power	21	21	21
	Total	**53**	**52**	**49**
Urea (XtU)	Urea	29	28	25
	Power	22	22	22
	Total	**51**	**50**	**47**

Case 4. Variation of feedstock: Impact of short-term feedstock price variation.

This case study was used to investigate the impact of short-term feedstock price variation on the economics of chemical/mid-load[6] power plants. The main difference with Case 3 is that the feedstock (TOPS and coal) prices were varied on a weekly basis to simulate a variable market. The NPV was compared with those of a static facility using only coal as feedstock.

[6] Mid-load or intermediate power plants are deployed after the main base (nuclear and coal) power plants and renewable (wind and solar) electricity generation capacity, but before the peak (gas) power plants. This roughly means that during working days mid-load power plants are operated at full capacity between 08:00 u–20:00 u. Outside this time-window the power plants are operating at considerably lower capacity.

Case 5. Variation of production: Producing mainly chemicals/fuels during off-peak hours and mainly electricity during peak hours.

This case study was used to investigate whether and under which economic conditions operating an IG-PG facility as a chemical/mid-load[6] power plant pays off. It was assumed that the IG-PG facilities used a fixed biomass/coal feedstock mixture. During peak hours electricity production was maximised and during off-peak hours chemical/fuel production was maximised. For both extremes a 40% minimal load restriction was maintained [20]. Operating the IG-PG facility this way ensured that the gasifier, syngas cleaning and acid gas removal (AGR) sections remained at nominal load and only the chemical/fuel and power sections varied in load. Production was switched from chemical/fuel to electricity when the electricity market price increased above the chemical–electricity equivalent price (PEP), see Section 2.5. The chemical/fuel (FT-liquids, methanol and urea) price was varied on a weekly basis to simulate fluctuations in product prices. The average NPV were compared to the NPV of a static facility with the same chemical/fuel as main product and operating in the same market.

Case 6. Retrofitting FT producing IG-PG facilities to methanol or H_2 producing IG-PG facilities.

This case study was used to evaluate the economic implications of retrofitting an IG-PG facility during the economic lifetime of the facility (2015–2045 with the retrofit in 2035). The preferred fuel mix for transportation may change in the coming decades from gasoline/diesel to methanol, hydrogen or electricity. Therefore, in this case study an IG-PG facility producing FT-fuels was retrofitted after 20 years to produce another transportation fuel (methanol) for another 10 years. The economics of this retrofit were compared to an IG-PG facility producing methanol for 30 years.

As indicated, in Case 3 till 5, the economic performance of IG-PG facilities under market conditions with fluctuating commodity prices was calculated. For this analysis, the economic lifetime of the facilities was divided into individual hours. For each hour, the most economic feedstock or production type was determined.

Prices were varied, depending on the case study. In Case 3, only the electricity price was varied. Case 4 had fluctuating electricity and feedstock prices. The chemical/fuel prices behaved according to the scenarios. The analysis was performed using four different CO_2 credit prices, based on the results of Case 3. In Case 5, the chemical/fuel and electricity prices were fluctuating. The feedstock and CO_2 credit prices behaved according to the scenarios.

The method of variation was identical for all case studies. In Cases 3 and 4, base load electricity production was sold for 15.7 €/GJ (Table 3). The additional electricity was sold according to the historical Dutch day–hourly market price between 2004 and 2008 [6]. This data was repeated 5 times to obtain electricity prices spanning 20 years. In Case 5, also the base load electricity production was sold for the day–hourly prices. Random values were selected for the feedstock, chemical/fuel or CO_2 price variations. These random values were based on the historical data using a Gauss distribution, have a minimum of zero and were altered every 168 h. The analysis was repeated 200 times, resulting in the average economic performance of IG-PG facilities under short-term market variations. Case 3 was performed for the *Current Situation* scenario only, while cases 4 and 5 were performed for all scenarios.

2.3. Scenarios

Five scenarios were used to explore the impact of possible future global trends in primary energy carrier prices and policy developments, e.g., CO_2 price. The scenarios contain different price ranges and dynamics for biomass pellet, coal, CO_2 credit and CO_2 transport and storage costs. The values used were based on historical market prices and projections of the Netherlands Environmental Assessment Agency (PBL) [21,22], European Commission [23], IEA [24] and studies commissioned by Greenpeace [25,26]. The commodity price model is discussed in more detail in Section 3.1.

Scenario 1. Current Situation scenario

In this scenario current production costs were calculated using the commodity price levels at the beginning of 2010, which were 6.3 €/GJ for biomass pellets [1,2], 1.5 €/GJ for coal [5], 10.1 €/GJ for gasoline/diesel [27], 11.0 €/GJ for methanol [4] and 19.0 €/GJ for urea [28]. See Section 3.1 for the justification.

Scenario 2. Business as Usual scenario (B as U)

This scenario assumed modest CO_2 mitigation policies, resulting in a slight increase in CO_2 credits price. It was assumed that the limited incentive for GHG reduction will result in a limited substitution of coal by biomass, leading to in a minor increase in biomass pellet prices and a minor decrease in coal prices [21,22,24]. Without a strong incentive for CCS, no large-scale CO_2 transport infrastructure will be build, limiting the CO_2 transport network to smaller single source-single sink pipelines. Therefore, CO_2 transport and storage costs remained constant at 15.0 €/t CO_2 for the whole time period (2015–2035) [29].

Scenario 3. Direct Action scenario (DA)

This scenario assumed stringent CO_2 policies, resulting in a strong increase in the price of CO_2 credits. This leads to a gradual transition from a fossil-based energy infrastructure towards a renewable-based energy infrastructure. The rate at which biomass pellet prices increased and coal prices decreased were higher compared to the *Business as Usual* scenario. The higher CO_2 credit price will result in the development of a large-scale CO_2 transportation network and, consequently, lower CO_2 transport and storage costs.

Scenario 4. Green scenario

This scenario assumed much higher coal prices and much lower biomass pellet prices compared to the previous scenarios. Literature studies show that biomass pellet prices could drop to 3.0 €/GJ due to technical learning, e.g., improved cultivation techniques, mature market and efficient local pre-treatment [30–33]. In 2008, coal prices exceeded 5.0 €/GJ in NW-Europe [34]. In this scenario it was assumed that biomass pellet prices drop gradually to 3.0 €/GJ, while coal prices rise gradually to 3.0 €/GJ. One option to reduce net CO_2 emissions is to replace coal by (sustainable) biomass. The CO_2 mitigation penalty of this option consists mainly of the price difference between coal and biomass. Due to the converging of biomass and coal prices, reducing net CO_2 emissions using this option becomes less expensive. Therefore, in this scenario it was assumed that CO_2 credit prices remained constant. Both the CO_2 credit price and CO_2 transport and storage costs were based on the *Current Situation* scenario.

Scenario 5. Delayed Climate Policy scenario (DCP)

This scenario assumed that a trigger point occurred in 2025. Up to 2025 limited CO_2 policies were assumed. After 2025, very stringent CO_2 policies are implemented. Dependency of fossil fuels will remain high up to the trigger point. The stringent CO_2 policies will result in a rapid transition from a fossil-based energy infrastructure towards a sustainability-based energy infrastructure. Up to 2025, feedstock and CO_2 credit prices behaved as in the *Business as Usual* scenario. After 2025 the rate at which commodity prices and CO_2 credits changed was doubled. Starting 2025, a large-scale CO_2 transport network is rapidly deployed, resulting in a reduction of CO_2 transport and storage costs.

2.4. Total capital investment

Total capital investments (TCI) were calculated using the Factored Estimation method. In this method, the cost of each major component is estimated using data from open literature sources and expert interviews. These cost data correspond to a specific scale and is adjusted to the required scale. An installation factor, representing e.g., infrastructure, overhead, engineering and contingencies, is added to the scaled component capital costs. The TCI is the summation of the scaled component costs, including installation factor, of the individual components. The used component capital costs, scaling factors and installation factor are given in Section 3.2.

The Factored Estimation method has an inherent uncertainty of approximately 30% [35]. Besides the inherent uncertainty, the method has two limitations. One limitation is the volatility of the equipment prices. In the last years, capital costs varied significantly, increasing rapidly from 2005, peaking late 2008 and decreasing thereafter [36]. A study made by CERA on the capital costs of US- and EU-based power plants, excluding nuclear, shows a steady increase from 2000 onwards. Capital costs peaked in the EU beginning 2008 (index = 180, base year is 2000), while in the U.S. this peak occurred beginning 2009 (index = 188, base year is 2000). Since that peak, capital costs dropped by 12% (EU) and 7% (US) [37]. Early 2010, prices were back at mid 2006 (EU) or mid 2007 (US) level (Fig. 4). This volatility resulted in benchmarking studies requiring updating in relatively short time spans. For instance, FosterWheeler (FW) updated its analysis of the cost effectiveness of IGCC-CCS published in July 2007 [7] already in August 2008 [8]. The updated study has an increase in capital costs of 20%.

The second limitation is the uncertainty of the component capital costs. This is highlighted by comparing the FW studies [7,8] with a study performed by NETL [9]. Both studies calculate the production costs of a coal-fired IGCC, albeit with slightly different base year, scale and technology. After correcting for

those factors, specific capital costs in the NETL study are still 24% higher than those in the FW study.

Capital investment for a given component depends on its scale. The required scale was provided by the technical model (see Section 2.1). To scale the capital investment from a known scale and cost, Eq. (1) was used. If the required scale exceeds the maximum scale of a component, multiple identical components in parallel are needed. Installing identical components in parallel gives a small cost reduction. [14] This reduction was calculated using Eq. (2).

$$y_s = y_0 \times \left(\frac{x_s}{x_0}\right)^S \tag{1}$$

$$y = y_s \times n^m \tag{2}$$

where y, y_s and y_0 are actual scaled and initial costs respectively; x_s and x_0 are actual and initial scale respectively; S is scaling factor; n is desired number of units; and m is multiplication exponent (=0.9).

2.5. Economic model

The economics of the different case studies and scenarios were evaluated by calculating the production costs of the main product using the Net Present Value (NPV) method [38], see Eq. (3). By setting the NPV to zero the production cost of the main product was calculated. Note that in the economic analysis only stored CO_2 was exempted from CO_2 credits. Carbon locked in chemical/fuel products were counted as if it was emitted.

$$\mathrm{NPV} = -I + \sum_{i=o}^{L} \frac{B_i - C_i}{(1+r)^i} \tag{3}$$

where B and C are annual revenues (benefits) and costs respectively r is discount rate L is plant economic lifetime (years) I is total capital investment cost I is year

Common parameters used in all case studies and scenarios are displayed in Table 2. Based on other studies, a construction time of three years was assumed and capital costs were evenly divided over these years [8,9,11,12].

In Cases 3–5 a feedstock equivalent price (FEP) price and a production equivalent price (PEP) were calculated to determine the break-even point in feedstock and production price respectively. FEP is the electricity price at which the feedstock should be switched from biomass to coal. Note that the production of chemicals is kept constant; the additional energy is used for electricity production only. PEP is the electricity price at which production should be switched from chemical to electricity. The FEP and PEP were calculated according to the following equations:

$$\mathrm{FEP} = \frac{(\Delta E_{Bio} P_{Bio} + \Delta E_{Coal} P_{Coal}) - (\Delta E_{Slag} P_{Slag} + \Delta E_{Sulphur} P_{Sulphur}) + \Delta E_{CO_2} P_{CO_2}}{\Delta E_{Electricity}} \tag{4}$$

$$\mathrm{PEP} = \frac{\Delta E_{Chemical} P_{Chemical} - \Delta E_{CO_2} P_{CO_2}}{-\Delta E_{Electricity}} \tag{5}$$

where FEP is feedstock equivalent price (€/GJ) PEP is production equivalent price (€/GJ) ΔE_x is difference in input or output of commodity × (energy flow (GJ/yr) for feedstock, main product and electricity or mass flow (kt/yr) for by-products and CO_2) P_x is price of commodity × (€/GJ for feedstock, main product and electricity or €/kt for by-products and CO_2)

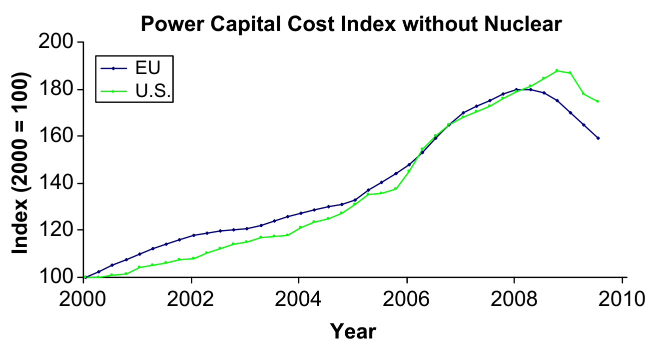

Fig. 4. Relative capital costs for non-nuclear power plants [37].

Table 2
Economic assumptions IG-PG facilities.

Parameter	Unit	Value
Location	–	NW-Europe
Construction time	Year	3
Plant economic lifetime (L)	Year	20
Discount rate (r)	%	10
Operating fraction	%	90
O&M costs	% of cap. cost	4

3. Economic data

3.1. Commodity prices

To estimate the feedstock and CO_2 credit prices during the lifespan of the facilities (2015–2035) for each scenario, historical data were combined with price projections from other studies (see supplementary data). For coal and CO_2 credits the WEO [24] projections were used. For biomass pellets, projections from the PBL [22] were used as WEO data were missing. Prices used are displayed in Figs. 5–7. For the end-products no future projections were made. Instead, the prices as of beginning 2010 as well as the minimum and maximum values of the historical prices were used (Figs. 8–10).

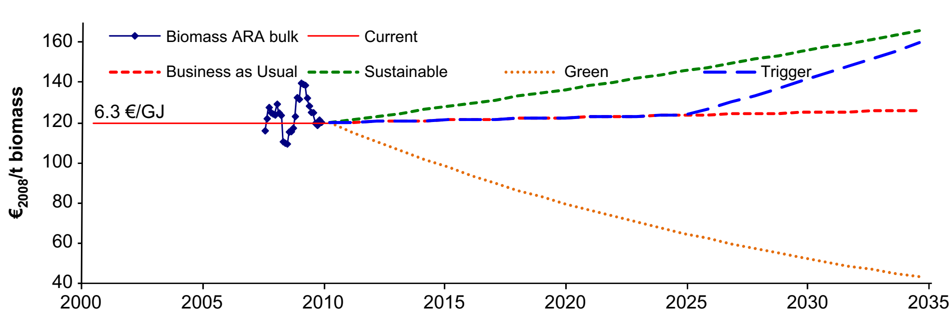

Fig. 5. Historical (left) and projected (right) bulk biomass pellet prices for the different scenarios [1,2].

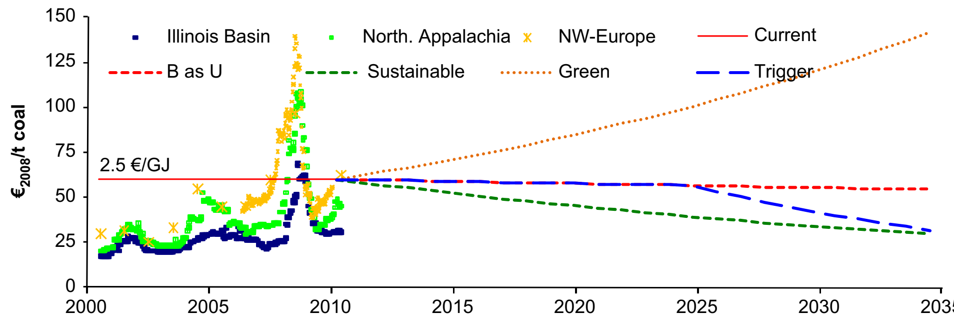

Fig. 6. Historical (left) and projected (right) coal prices for the different scenarios. The historical coal prices were on a weekly basis. The NW-Europe prices prior to May 2006 were on a yearly basis [5,34].

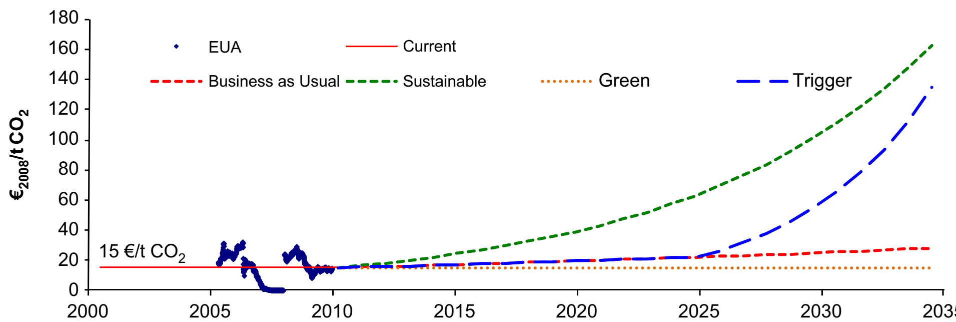

Fig. 7. Historical (left) and projected (right) European Union Allowance (CO_2 emission rights) spot prices for the different scenarios [3].

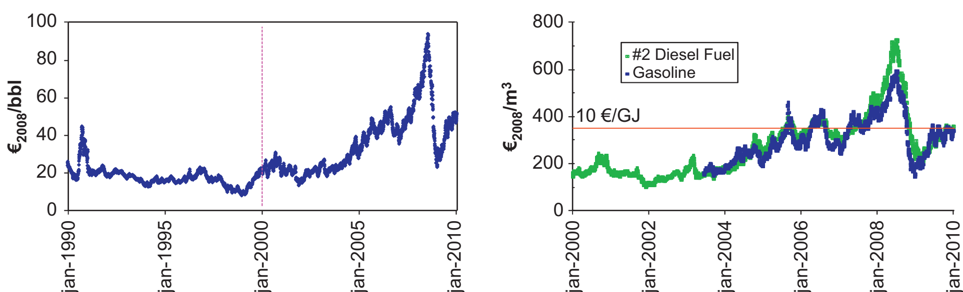

Fig. 8. Historical Brent crude oil (left) and oil products (right) prices, excluding duties and taxes [27].

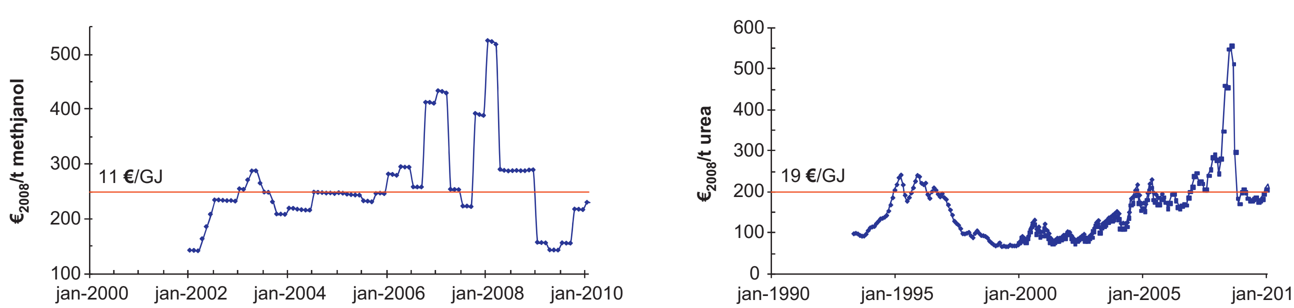

Fig. 9. Historical methanol [4] (left) and urea [28] (right) prices.

Biomass pellet prices are volatile. The market is relatively small and immature. Therefore, a moderate change in demand can lead to a large variation in price. It is expected that, as the biomass pellet market grows, price spikes will become rarer and less severe. The small and immature market makes long term projections of biomass pellet prices uncertain and significant differences between future projections have been found. As already indicated in Section 2.3, biomass pellet prices were expected to drop due to technical learning in the long term [30–32].

Coal prices have been relatively stable between 2000 and 2007. In 2007 prices rose sharp due to a large increase in demand. Prices fell again due to the economic crisis. It is expected that prices will rise significantly again when the global economy recovers. NW-Europe coal is delivered at ARA (Amsterdam–Rotterdam–Antwerp) and is, on average, 1.5 times more expensive than Northern Appalachia coal. Contrary to biomass pellets, where technical learning could reduce prices considerable, coal production is already well developed. Therefore, no strong reductions in production costs due to learning are expected. At the

same time, strong increases in production costs due to depletion of (cheap) mining sites are expected. It is, therefore, likely that coal prices will increase in the long term. When this will happen is outside the scope of this study. The impact of increasing coal prices was investigated in the *Green* scenario.

The CO_2 credit price collapsed during the height of the economic recession. Since then prices have stabilised at 15 €/t CO_2. Mulder et al., analysed the CO_2 credit market and concludes that CO_2 credit prices will remain around this price due to an abundance of CO_2 emission rights. However, the CO_2 credit market is an artificial market. The number of available CO_2 emission rights emitted by the European Union can directly influence CO_2 credit prices [39].

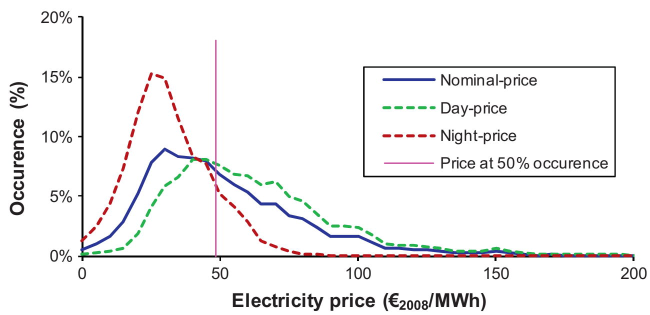

Fig. 10. Electricity price distribution in the Netherlands during 2004–2008. [6]. The vertical line in the graph marks half of the occurrences.

The IEA World Energy Outlook 2010 current policy scenario assumes that oil prices will more than double between 2009 and 2025 and then start to stabilise at almost 100 $€_{2008}$/bbl (135 $\$_{2009}$/bbl) in 2035, exceeding the 2008-spike. However, forecasting the oil price is difficult as uncertain factors, e.g., geo-political stability and world economy, have a direct influence on the oil price.

Methanol prices were relatively stable at 200 €/t between 2002 and 2006. The past several years saw some large price spikes. These spikes were caused both by an increase in demand and a shutdown of production facilities due to maintenance [4]. Since early 2010 methanol prices continued to rise to over 300 €/t, while the market remained volatile due to a small buffer between supply and demand.

For the past decades urea prices were fluctuating between 50 and 200 €/t. In the last few years urea prices spiked to over 500 €/t. The World Bank expects that up till 2020 urea prices will fluctuate around 175 €/t [28]. The International Fertilizer Industry Association indicates that in the coming years production capacity will increase more rapidly than supply, resulting in more stable and possibly lower prices [40].

Electricity prices are fluctuating constantly. In NW-Europe, in general a distinction can be made between day (peak) and night (off-peak) prices. As can be seen in Fig. 10, peak prices are significantly higher. Future electricity prices will depend on feedstock prices, status of the economy, penetration rate of renewable as well as other energy sources, technological developments, political decisions and weather conditions. As an example, the announced shutdown of German nuclear power plants can influence the production costs of electricity in NW-Europe.

Table 3
Commodity prices.

Commodity	Parameter	Unit	Scenarios					
			Current	Business as Usual	Sustainable	Green	Trigger	
							2015–2025	2025–2035
Feedstock	EP	€/GJ	6.3[a]	+0.2%/yr	+1.3%/yr	−3.2%/yr	+0.2%/yr	+2.6%/yr
	TOPS	€/GJ	6.3[a]	+0.2%/yr	+1.3%/yr	−3.2%/yr	+0.2%/yr	+2.6%/yr
	Coal	€/GJ	2.25[b]	−0.4%/yr	−2.8%/yr	+2.8%/yr	−0.4%/yr	−5.6%/yr
CO_2	CO_2 credits	€/t CO_2	15.0[c]	+2.5%/yr	+10%/yr	15.0	+2.5%/yr	+20%/yr
	CO_2 transport& storage costs	€/t CO_2	10.0[d]	15.0[d]	10.0–15.0[e]	10.0	15.0[e]	10.0[e]
Reference End-product Prices								
Current product prices	FT-fuel	€/GJ	10.1(3–21)[f]					
	Methanol	€/GJ	11.0(6–23)[g]					
	Urea	€/GJ	19.0 (6–53)[h]					
	Electricity	€/GJ	15.7(0–290)[i]					
	Slag	€/t	0					
	Sulphur	€/t	100					

[a] Biomass pellet prices were 120 €/t ARA (Amsterdam–Rotterdam–Antwerp) beginning 2010. Assuming an energy density of 19 GJ/t, this resulted in 6.3 €/GJ. TOPS are not produced commercially today. Although torrefaction results in additional costs, it was assumed that the reduction in transportation costs compensates this [41]. Therefore, it was assumed that the price for TOPS is also 6.3 €/GJ. Note that future improvements in torrefaction technology can result in delivery prices of TOPS being lower than those of EP [41]. During 2007–2010 biomass pellet prices fluctuated between 5.7 and 7.3 €/GJ [1,2].

[b] Coal prices were 56 €/t ARA beginning 2010. Assuming an energy density of 25 €/GJ, this resulted in 2.25 €/GJ. During 2000–2010 coal prices fluctuated between 1.0 and 5.6 €/GJ [34].

[c] CO_2 credit prices were fluctuating around 15 €/t CO_2 beginning 2010. Between 2005 and 2010 CO_2 credit prices fluctuated between 0 and 32 €/t CO_2 [3]. Note that for the economic analysis, carbon locked in the chemical/fuel products are considered emissions and must be compensated by CO_2 credits.

[d] In the *Business as Usual* scenario it was assumed that no large-scale CO_2 transport infrastructure will be realised. Therefore, the CO_2 transport and storage price remained at 15 €/t [29].

[e] In the *Direct Action* scenario it was assumed that a large-scale CO_2 transportation infrastructure would be realised. Costs dropped by 4% per year from 15 €/t CO_2 in 2015 to 10 €/t CO_2 in 2025. After that, CO_2 transport and storage costs remained at 10 €/t CO_2. In the *Delayed Climate Policy* scenario it was assumed that CO_2 transport and storage costs remained at 15 €/t CO_2 up till 2025, similar to the *Business as Usual* scenario. In 2025 rapid deployment of a large-scale infrastructure will bring CO_2 transport and storage costs down to 10 €/t CO_2 for the period 2025–2035 [29].

[f] Gasoline and diesel prices excluding duties and taxes were 350 €/m^3 in NW Europe beginning 2010. Assuming an energy density of 45 GJ/t and a mass density of 770 kg/m^3, this resulted in 10.1 €/GJ. During 2000–2010 gasoline and diesel prices fluctuated between 3 and 21 €/GJ. During that time, Brent oil prices fluctuated between 13 and 94 €/bbl (2–15 €/GJ) [27].

[g] Methanol prices were fluctuating around 250 €/t beginning 2010. Assuming an energy density of 22.7 GJ/t, this resulted in 11.0 €/GJ. During 2002–2010 methanol prices fluctuated between 6 and 23 €/GJ [4].

[h] Urea prices were 200 €/t beginning 2010. Assuming an energy density of 10.5 GJ/t, this resulted in 19 €/GJ. During 1993–2010 urea prices fluctuated between 6 and 53 €/GJ [28].

[i] Electricity prices were based on the average Dutch day–hourly market price between 2004 and 2008. The observed trends were considered representative for NW-Europe. During that period the electricity price varied between 0 and 1050 €/MWh (0–290 €/GJ), with an average price of 57 €/MWh (15.7 €/GJ) [6].

3.1.1. Commodity price projections

Price projections used in this study are summarised in Table 3. Note that the product prices from early 2010 were taken as reference.

3.2. Capital costs data

Several literature sources were used to obtain component capital cost data. The main characteristics of these studies are given below. The selected data and argumentation is given in Table 4 and its footnotes.

- IEA GHG study *Co-production of hydrogen and electricity by coal gasification with CO_2 capture*, performed by FosterWheeler (FW) in 2007 [7] and the economic update performed in 2008 [8].
  This study calculates, among other, electricity production costs of IGCC facilities both with and without CCS. A Shell EF gasifier, Selexol AGR removal, Claus/SCOT sulphur removal and 9FA GE gas turbines are considered. Australian bituminous coal is used as feedstock. The CO_2 in the CCS facility is compressed to 110 bar. The main economic parameters are 10% discount rate, 25 years economic lifetime and a coal price of 1.2 €$_{2007}$/GJ$_{LHV}$. Capital costs are calculated on a component level, but only given on an aggregated level (gasifier, gas cleanup, power island, etc.). The 2008-study has identical technical configuration and technical performance as the 2007-study. The only difference is that the capital costs and coal price have been updated to reflect the rise in feedstock and construction prices.
- NETL study Cost and Performance Baseline for Fossil Energy Plants in 2007 [9].
  This study calculates electricity production costs of various fossil fuel power plants. This includes a Shell EF IGCC power plant with and without CO_2 capture. The used technology is a Shell EF gasifier, Sulfinol AGR removal (for vent) or Selexol AGR removal (for CO_2 capture), Claus/SCOT sulphur removal and MS7001FB gas turbines. Illinois #6 coal is used as feedstock. The CO_2 in the CCS facility is compressed to 153 bar. The main economic parameters are 10% discount rate, 30 years economic lifetime and a coal price of 1.2 €$_{2007}$/GJ$_{HHV}$. Capital costs are calculated on a component level for the U.S. Midwest.
- Several studies from Princeton Environmental Institute by Williams, Larson et al. [10–14].
  These studies investigate the conversion of biomass and coal to transportation fuels using a bottom-up approach on the component level using AspenPlus. Studied are the conversions of coal to FT-liquids and methanol, biomass to FT-liquids, and a mixture of coal and biomass to FT-liquids. In the process configurations considered, dedicated gasifiers are assumed for biomass and coal conversion to syngas (fluidised bad gasifier for biomass, GE entrained flow gasifier for coal). Capital costs are calculated on a component level, using a database which was updated in 2007.
- Hamelinck et al. Future prospects for production of methanol and hydrogen from biomass in 2002 and Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential in 2004 [16,17].

These studies calculate production costs and efficiencies of biomass to methanol, hydrogen and FT-liquids for different process configurations. The scale investigated ranges between 80 MW$_{th}$ and 2000 MW$_{th}$ input. No entrained flow gasifiers were evaluated in these studies. As in the previous studies, capital costs are calculated on a component level. Although the biomass to methanol and biomass to hydrogen process configurations considered differ from our study, many components are the same.

The cost data of the 2007 FW study have been used as point of departure, as beginning 2010 the capital costs for power plants were back at their 2007-level [37]. When large differences occurred between the cost data of the different sources, an expert judgement was made in selecting which source to use. The exact component cost data and motivation to select the data are given in Table 5 and its footnotes.

In Table 5, the base costs are the bare equipment costs. These were increased by the installation factor (IF), which consisted of direct (instrumentation and control, buildings, grid connection, site preparation, civil works, electronics and piping) and indirect (engineering, building interest, contingency, fees, overhead, profits and start-up costs) costs. The direct costs decreased with increasing scale, using a scaling factor of -0.18 [17]. When no values for the direct and indirect costs are available, 33% direct and 50% indirect costs were assumed at the scale used in the original literature source [17]. It was assumed that the IG-PG facilities consist of two main trains (see Fig. 11), with four parallel feedstock pre-treatment set-ups. Depending on the production, up to 3 parallel chemical conversion trains were used.

4. Results

In this section, results are presented per case study. This is followed by a sensitivity analysis of the *Current Situation* scenario. Detailed breakdowns of costs, revenues and component capital cost are given in the supplementary data.

Table 4
Summary of key results on conversion system performance from the considered studies.

Feedstock	Product	Energy input (MW$_{HHV}$)	CO_2 capture	Efficiency (chem.+elec.)	Production costs	Source
Coal	Electricity	1884	No	40%	52 €$_{2007}$/MWh	[7]
Coal	Electricity	2053	Yes	32%	72 €$_{2007}$/MWh	[7]
Coal	Electricity	1884	No	40%	70 €$_{2008}$/MWh	[8]
Coal	Electricity	2053	Yes	32%	94 €$_{2008}$/MWh	[8]
Coal	Electricity	1547	No	41%	59 \$$_{2007}$/MWh	[9]
Coal	Electricity	1616	Yes	32%	78 \$$_{2007}$/MWh	[9]
Coal	FT-liquids	7624	No	33%+17%	8.2 \$$_{2007}$/GJ	[10]
Coal	FT-liquids	7624	Yes	33%+14%	10.5 \$$_{2007}$/GJ	[10]
Switch grass	FT-liquids	661	No	45%+5%	28.5 \$$_{2007}$/GJ	[10]
Switch grass	FT-liquids	661	Yes	45%+4%	30.5 \$$_{2007}$/GJ	[10]
Coal+Switch grass	FT-liquids	2099+661	Yes	32%+15%	17.1 \$$_{2007}$/GJ	[10]
Coal	Methanol	2870	No	25%+22%	8.0 \$$_{2002}$/GJ	[12]
Coal	Methanol	2870	Yes	25%+20%	9.9 \$$_{2002}$/GJ	[12]
Biomass	Methanol	1000	No	57%+0%	7.6 \$$_{2001}$/GJ	[16]
Biomass	Hydrogen	1000	No	70%−5%	7.0 \$$_{2001}$/GJ	[16]
Biomass	FT-liquids	1000	No	42%+4%	14.6 €$_{2002}$/GJ	[17]

Table 5
Selected capital costs of the components of the IG-PG facilities investigated.

Component	Base cost (M€$_{2008}$)	Base scale	Scaling factor	Scale unit	Direct costs (%)	Indirect costs (%)	# units[a]
Pre-treatment and feeding							
Biomass[b]	10	65	0.77	tonne a.r./h	27	25	0–4
Coal[c]	41	273	0.65	tonne a.r./h	53	14	0–4
Gasification							
Air separating unit (95% O_2)[d]	112	5149	0.8	tonne output/d	37	16	2
Shell EF gasifier[e]	139	2053	0.66	MW_{HHV} coal eq.	73	24	2
Gas cleaning							
Candle filter [(1)]	2	12	0.65	gas m^3/s	33	50	2
Wet scrubber[f]	3	12	0.7	gas m^3/s	33	50	2
Heat exchanger[f]	9	138	0.6	MW_{th}	31	40	2
Sour WGS reactor[g]	14	8819	0.65	H_2+CO kmol/h	0	81	2
Guard bed[h]	0	0.6	1	gas Nm^3/s	0	200	1
Sweet WGS reactor[g]	14	8819	0.65	H_2+CO kmol/h	0	81	1
H_2 PSA[h]	12	16,616	0.65	H_2 kmol/h	100	28	1
Acid gas removal							
Rectisol AGR removal[i]	120	554	0.7	CO_2 tonne/h	33	50	1
Claus/SCOT[j]	16	56	0.67	S tonne/d	33	14	1
Power isle							
Gas turbine[k]	42	266	0.75	Net MW_e	16	27	1–2
Steam turbines and cycle[l]	38	275	0.67	Gross MW_e	16	27	1
HRSG[m]	34	355	1	MW_{th} exch.	16	27	1
FT isle							
FT slurry reactor[n]	21	131	0.72	MW_{HHV} FT	33	50	0–3
Product upgrading[n]	132	220	0.7	FT tonne/h	33	50	0–3
MeOH isle							
MeOH reactor[o]	13	42	0.65	MeOH tonne/h	15	50	0–1
Product upgrading[o]	1	17	0.65	MeOH tonne/h	15	50	0–1
Urea isle							
Ammonia production[p]	150	2000	0.7	NH_3 tonne/d	33	50	0–1
Urea reactor+upgrading[p]	150	3500	0.7	urea tonne/d	33	50	0–1
CCS							
CO_2 compression[q]	6	13	1	MW_e	16	32	1
Miscellaneous							
Syngas compressor[q]	4	10	1	MW_e	16	32	Varies

[a] Number of units depends on the used configuration. A total of four feeding trains are used, divided over biomass and coal. The division depends on the biomass/coal ratio. The gasifier and gas cleaning sections have two trains. Before the AGR, the syngas streams combine. Downstream, only one train was used. The maximum output of each gas turbine was fixed at 302 MW_e, meaning 2 gas turbines are needed in the coal to liquid case and all power cases. Currently the GT-26 is rated at 289 MW_e [42].

[b] This includes the storage, handling and feeding of the biomass pellets. A scaling factor of 0.77 [11,17] is reported. [11] reports, corrected for feeding at 40 bar, 14 M\$$_{2007}$ for 65 t as received (a.r.) wood/h and an IF of 59%. [17] reports 11 M€$_{2002}$ for 34 t a.r. wood/h and an IF of 100%. This translates to 17 M€ and 47 M€ respectively for 76 t a.r. wood/h (≈ 366 MW_{HHV} biomass). The value of [11] was taken as they are for a Nth facility, while the data from [17] is for a first-of-a-kind facility.

[c] This includes the storage, handling and feeding of the coal. Scaling factors between 0.63 [8] and 0.65 [9] are reported. A scaling factor of 0.65 was used. [8] reports 40 M€$_{2007}$ for 273 t a.r. coal/h and an IF of 74%. [9] reports 118 M\$$_{2006}$ for 215 t a.r. coal/h and an IF of 73%. This translates to 71 M€ and 73 M€ respectively for 66 t a.r. coal/h (≈ 500 MW_{HHV} coal). The value of [8] was taken.

[d] This includes the air separation unit and the oxygen compression to 40 bar. Scaling factors of 0.5 [11], 0.75 [17] and 0.8 [8] are reported. A scaling factor of 0.8 was used. [8] reports 110 M€$_{2007}$ for 5150 t/d and an IF of 53%. [9] reports 144 M\$$_{2007}$ for 4070 t/d and an IF of 20%. [17] reports, corrected for 40 bar, 27 M€$_{2002}$ for 576 t/d and an IF of 30% for the ASU and 21 M€$_{2002}$ for 13 MW_e and an IF of 72% for the oxygen compressor. This translates to 170 M€, 146 M€ and 205 M€ respectively for 2493 t/d. The value of [8] was taken.

[e] Scaling factors of 0.66 [8], 0.67 [11] and 0.7 [43] are reported. A scaling factor of 0.66 was used. [8] reports 137 M€$_{2007}$ for 2053 MW_{HHV} and an IF of 98%. [9] reports 128 M\$$_{2007}$ for 1618 MW_{HHV} and an IF of 114% [43] reports 120 M€$_{2005}$ for 600 MW_{HHV} and an IF of 10%. This translates to 276 M€, 222 M€ and 199 M€ respectively for 1000 MW_{HHV}. The value of [8] was taken as it is the most up-to-date and in €.

[f] Data was taken from [17] and indexed to €$_{2008}$.

[g] Scaling factors of 0.65 [17] and 0.67 [11] are reported. A scaling factor of 0.65 was used. [9] reports 8.8 M\$$_{2006}$ for 1,533 MW_{HHV} coal input (≈ 15,500 kmol (H_2+CO)/h) and an IF of 84%. [17] reports 12 M€$_{2002}$ for 8,819 kmol (CO+ H_2)/h and an IF of 81%. This translates to 6 M€ and 19 M€ respectively for 11,500 kmol (H_2+CO)/h (≈ 1,000 MW_{th} coal input). The value of [17] was taken as the value of [9] was deemed too low.

[h] Scaling factors of 0.65 [8], 0.7 [17] and 0.74 [14] are reported. A scaling factor of 0.65 was used. [8] reports 12 M€$_{2007}$ for 16,616 kmol H_2/h and an IF of 128%. [14] reports 7 M€$_{2002}$ for 1,058 kmol H_2/h, including BOP and indirect costs. [17] reports 33 M€$_{2002}$ for 9.600 kmol H_2/h and an IF of 69%. This translates to 17 M€, 17 M€ and 49 M€ respectively for 6,500 kmol H_2/h. The value of [8] was taken as it is the most up-to-date.

[i] Scaling factors of 0.63 [11], and 0.7 [17] are reported. A scaling factor of 0.7 was used. [9] and [11] use a Selexol based AGR. Using Rectisol instead of Selexol increases costs by 75%. [8] reports 119 M€$_{2007}$ for 554 t CO_2/h and an IF of 100%. [9] reports, after correction, 104 M\$$_{2006}$ for 453 t CO_2/h and an IF of 189%. [11] reports 52 M\$$_{2007}$ for 200,000 Nm^3/h (≈ 82.5 t CO_2/h at a CO_2 concentration of 21 mol%) and an IF of 59%. [17] reports, after correction, 55 M€$_{2002}$, for 436 t CO_2/h assuming a IF of 100%. This translates to 180 M€, 181 M€, 148 M€ and 108 M€ respectively for 345 t CO_2/h. The value of [8] was taken as it is the most up-to-date and in €. A direct cost factor of 33% at a scale of 554 t CO_2/h and an indirect cost factor of 50% was assumed.

[j] A scaling factor of 0.67 [9,11] is reported. The Claus and Scot units receive the acid gas stream after Rectisol processing. This stream has a higher sulphur content than after Selexol processing. This reduces costs by 46%. [8] reports 21 M€$_{2007}$ for 56 t S/d and a IF of 14%. [9] reports, after correction, 5 M\$$_{2007}$ for 129 t S/d and a IF of 228%. [11] reports 25 M\$$_{2007}$ for 137 t S/d and a IF of 52%. This translates to 49 M€, 13 M€ and 29 M€ respectively for 160 t S/d. The value of [8] was taken as it is the most up-to-date and in €.

[k] Scaling factors of 0.7 [44] and 0.75 [11] are reported. A scaling factor of 0.75 is used as, according to Kreutz et al.[11], this gave the best fit based on the Gas Turbine World's 2003 Handbook. [9] reports 44 M\$$_{2006}$ for 232 MW_e and a IF of 42%. [44] reports 17 M€$_{2003}$ for 26 MW_e and an IF of 100%. [11] reports 56 M\$$_{2007}$ for 266 MW_e and a IF of 47%. Using the scaling factor this translates to 61 M€, 243 M€, and 70 M€ respectively for 360 MW_e. Compared to quoted costs in the GTW 07/08 [42], with bare equipment costs of the gas and steam sections of a 400 MW_e combined cycle power plant around 136 M€, the value from Hamelinck is far too high. This is most likely a result from the low initial scale and the use of first generation data. The value from Princeton is taken as it is more up-to-date than the NETL data.

[l] Scaling factors of 0.66 [9], 0.67 [11] and 0.7 [44] are reported. A scaling factor of 0.67 was selected. [9] reports 33 M$$_{2006}$ for 230 MW$_e$ and a IF of 65%. [44] reports 5 M€$_{2003}$ for 10 MW$_e$ and a IF of 100%. [11] reports 51 M$$_{2007}$ for 275 MW$_e$ and a IF of 47%. Using the scaling factor this translates to 52 M€, 114 M€, and 61 M€ respectively for 360 MW$_e$. The value from Hamelinck appears too high, Most probably due to the use of first generation data. The value from Princeton is taken as it is More up-to-date than the NETL data.

[m] This is often incorporated with the steam or gas turbines. As the IG-PG facility has More heat streams than a normal IGCC, the costs of the HRSG are calculated separate. A scaling factor of 1.0 [11] is reported. According to [11] generating 355 MW$_{th}$ costs 46 M€.

[n] For the FT-synthesis a slurry reactor at 60 bar was used. Scaling factors of 0.72 [17] and 0.75 [11] are reported. The lowest scaling factor was selected. [11] reports 24 M$$_{2007}$ for 103 MW$_{HHV}$ FT and a IF of 67%. [17] reports, after correcting for 60 bar, 18 M€$_{2002}$ for 131 MW$_{HHV}$ FT and a IF of 100%.. Using the scaling factor this translates to 73 M€ and 92 M€ respectively for 400 MW$_{HHV}$ FT. The highest value was selected. The FT product upgrading data is based on [17], reporting a scaling factor of 0.7 and 233 M€$_{2002}$, including BOP and indirect costs, for 286 M^3 FT product. This translates to 37 M€ for 31 t FT/h ($\approx$ 400 MW$_{HHV}$).

[o] Scaling factors of 0.65 [12] and 0.72 [16] are reported for a once-through LPMeOH synthesis reactor and 0.291 [12] and 0.7 [16] for Methanol separation and purification. The value from [12] for the purification appears too low for a stand-alone facility. Therefore, a scaling factor of 0.7 were selected. [12] reports 13.6 M$$_{2002}$ for 42 t MeOH/h and a IF of 73% for the synthesis and 1.1 M$$_{2002}$ for 16.8 t MeOH/h and a IF of 73% for the purification. [16] reports 3.5 M$$_{2001}$ for 87.5 t MeOH/h and a IF of 110% for the synthesis and 15 M$$_{2001}$ for 87.5 t MeOH/h and a IF of 110% for the purification. Using these scaling factors, this translates to 40 M€, and 35 M€ respectively for the synthesis and purification of 100 t MeOH/h ($\approx$ 630 MW$_{HHV}$). The values from [12] were selected as they result in the highest capital costs.

[p] Production of 3500 t/d urea from natural gas has a capital investment of around 1000 M€. This is divided into 400 M€ for ammonia production, 300 M€ for urea production and 300 M€ for off-sites [45]. Producing ammonia from syngas removes the need of desulphurisation, reforming and shifting, but still requires an ammonia reactor, separation and recycling. Therefore, it is assumed that ammonia production from syngas has a capital costs 300 M€. The urea production capital costs are kept at 300 M€.

[q] Compressor costs are identical for all gas compressors, regardless of the content of the gas. The exceptions are the supercritical CO_2 compressor and the O_2 compressor. The O_2 compressor is, due to fire-hazards, non-lubricated, adding 40% to the costs [17]. The supercritical CO_2 compressor must handle a phase change during compression. Scaling factors of 0.67 [11], 0.85 [17] and 1.0 [46] are reported. A scaling factor of 1.0 was used as this data was supplied by a petro-chemical company. [11] reports 6 M$$_{2007}$ for 10 MW$_e$ and a IF of 52%. [17] reports 13 M€$_{2002}$ for 13 MW$_e$ and a IF of 72%. This translates to 15 M€ and 51 M€ respectively for 27 MW$_e$. Contrary to a Selexol system, the CO_2 stream coming from a Rectisol unit does not need drying. Capital costs data of the CO_2 compressor based on a Selexol system is lowered by -36% to account for the absence of drying section [14]. [9] reports, after removing the drying section, 11 M$$_{2006}$ for 28 MW$_e$ and a IF of 109%. [11] reports 8 M$$_{2007}$ for 13 MW$_e$ and a IF of 48%. [8] reports 42 M€$_{2007}$ for 52 MW$_e$ and a IF of 14%. Using the scaling factor this translates to 16 M€, 17 M€ and 26 M€ respectively for 27 MW$_e$. The highest value is taken. The data of [11] for the normal compressors falls within the costs estimated for the CO_2 compressor and is therefore selected. It is therefore assumed that their value for the CO_2 compressor is also the best.

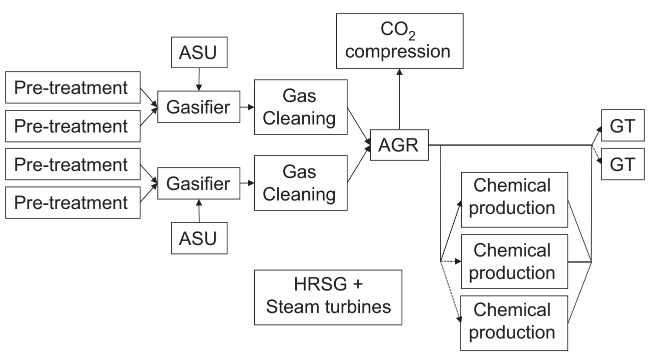

Fig. 11. Schematic representation of train configuration of IG-PG facility.

4.1. Static IG-PG facilities

Production costs of the main product of static IG-PG facilities under the *Current Situation* scenario varies between 9 and 38 €/GJ, depending on feedstock and product (see Fig. 13). Capital cost breakdowns of the different cases are given in Fig. 12. Detailed breakdowns of annual costs, revenues and capital costs are given in the supplementary data.

When producing electricity, FT-liquids or methanol, the gasifier represents the largest share of the capital costs (24%–33%), regardless of the feedstock used. When producing urea, the urea section represent the largest share of the capital costs (33%–36%), followed by the gasifier (18%–22%). In all cases the pre-treatment, gas cleaning and gas turbine equipment contribute less (combined 11%–22%).

Under *Current Situation* scenario conditions, none of the IG-PG facilities have production costs under the average market price of their products. The pure coal cases show significantly lower production costs than the biomass cases, mainly due to lower feedstocks costs and, to a lesser extent, a higher output which results in lower relative capital costs. Coal based production costs are 18 €/GJ for electricity; 13 €/GJ for FT-liquids; 12 €/GJ for methanol and 21 €/GJ for urea. Using TOPS results in lower production costs compared to using EP, with the largest difference occurring when producing urea ($\Delta=5.0$ €/GJ). Using TOPS results in production costs of 26 €/GJ for electricity; 19 €/GJ for FT-liquids; 22 €/GJ for methanol and 33 €/GJ for urea. The market price of the products has occasionally exceeded these values in the past years. The use of EP results in production costs of 29 €/GJ for electricity; 22 €/GJ for FT-liquids; 26 €/GJ for methanol and 38 €/GJ for urea. In the last decade, only electricity and urea had market prices reaching this value. Note that for the CO_2 credits, carbon locked in the products was treated as emissions. If the locked carbon would be treated as sequested carbon, production costs of the chemicals would be around 1 €/GJ lower than the values given above.

When producing chemicals, there is the option to capture CO_2 and venting it to the atmosphere. At a CO_2 credit price of 15 €/t CO_2, this slightly increases production costs (+ 0.1 €/GJ) when producing FT-liquids or methanol, as there is no need to compress the CO_2. When producing urea, CO_2 is needed as a feedstock and must be compressed. Consequently, venting the CO_2 increases production costs by 0.5 €/GJ.

Table 6 presents the impact of the different scenarios on the calculated production costs. When using coal as feedstock, production costs are lowest under *Current Situation* scenario conditions, being 12–21/GJ. Highest production costs are obtained in the *Direct Action* scenario, ranging between 14 and 27 €/GJ. The main reason is the higher CO_2 credit prices, increasing the production cost by 2.8–7.3 €/GJ, which is not compensated by the reduction in feedstock costs (-2.1 to -1.2 €/GJ). The increase in CO_2 transport and storage costs is small, raising production costs by 0.2–0.3 €/GJ. The *Business as Usual* and *Delayed Climate Policy* scenarios show similar trends as the *Direct Action* scenario, although the absolute variation due to decreasing coal price and increasing CO_2 credit and CO_2 transport and storage prices varies. The only differences between the *Green* and *Current Situation* scenarios are the feedstock costs. In the *Green* scenario, higher coal prices increase production costs by 1.8–3.0 €/GJ.

When using biomass as feedstock, production costs are lowest when using TOPS, being 1.8–5.0 €/GJ lower than when using EP. Therefore, only the results related to TOPS are discussed here. Lowest production costs are obtained under the *Green* scenario (15 €/GJ for FT-liquids till 26 €/GJ for urea production) due to the lower biomass pellet costs. Highest production costs are obtained under the *Business as Usual* scenario, ranging between 19 €/GJ for FT-liquids and 33 €/GJ for urea production. Production costs are affected in three ways. First, increasing TOPS prices raise production costs by 0.3–0.5 €/GJ. Second, higher CO_2 credit prices decrease production costs by 0.6–0.9 €/GJ as, contrary to the coal cases, stored CO_2 count as a revenue and emitted CO_2 or CO_2 locked in the chemicals/fuels are not charged. Third, the higher CO_2 transport and storage costs increase production costs by 0.6–0.9 €/GJ. The net effect is a small increase in production costs.

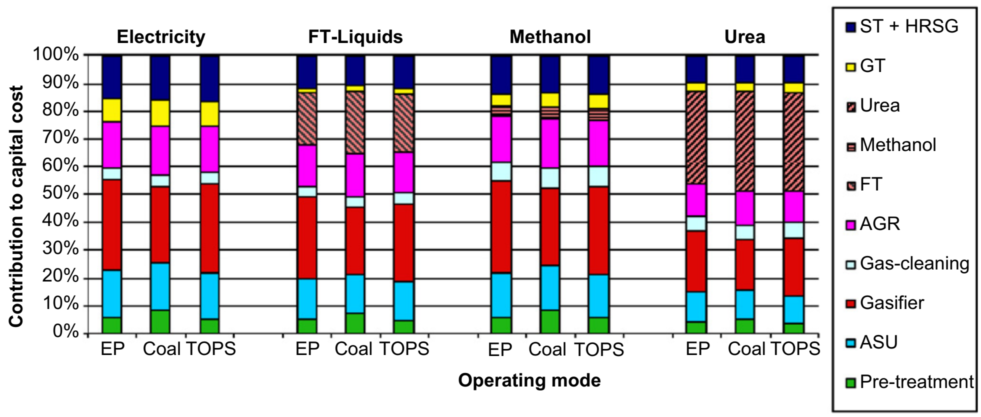

Fig. 12. Capital cost breakdowns static IG-PG facilities. The facilities use only one feedstock.

Table 6
Impact scenarios on production costs of static IG-PG facilities (€/GJ).

IG-PG facility	Production costs under different scenarios					
	Scenario	EP	EP/Coal	Coal	TOPS/Coal	TOPS
X to Electricity	Current	28.5	23.3	18.4	22.2	26.0
(Market price: 15.7 €/GJ	B as U	28.9	23.9	19.2	22.8	26.4
Range: 0–290 €/GJ)	Sustainable	25.6	23.1	20.6	22.2	23.8
	Green	23.5	22.0	20.5	20.9	21.2
	Trigger	27.7	23.6	19.6	22.5	25.5
X to FT-Liquids	Current	21.8	16.9	12.7	15.9	19.2
(Market price: 10.1 €/GJ	B as U	22.1	17.4	13.3	16.4	19.5
Range: 3–21 €/GJ)	Sustainable	19.3	16.7	14.4	15.9	17.3
	Green	17.4	15.8	14.4	14.8	15.1
	Trigger	21.1	17.1	13.7	16.1	18.7
X to Methanol	Current	25.9	18.7	12.4	17.1	22.2
(Market price: 11.0 €/GJ	B as U	26.4	19.5	13.4	17.9	22.6
Range: 6–23 €/GJ)	Sustainable	22.1	18.4	15.1	17.2	19.3
	Green	19.2	17.0	15.1	15.5	16.1
	Trigger	24.8	19.0	13.9	17.6	21.4
X to Urea	Current	37.9	29.0	21.1	26.8	32.9
(Market price: 19.0 €/GJ	B as U	38.4	29.8	22.3	27.7	33.4
Range: 6–53 €/GJ)	Sustainable	36.0	31.0	26.6	29.3	32.1
	Green	30.3	27.1	24.1	25.0	26.0
	Trigger	37.5	30.1	23.6	28.1	32.8

The *Direct Action* and *Delayed Climate Policy* scenarios show similar trends, but the higher CO_2 credit prices yield sufficient revenues to obtain a net reduction in production costs.

FT-liquids can be produced from TOPS for 19 €/GJ under *Current Situation* conditions. This roughly corresponds to an oil price of 105 €/bbl[7] (155 \$/bbl). However, with lower biomass pellet prices, as in the *Green* scenario, production costs decrease considerable. The 15 €/GJ production costs in the *Green* scenario is break-even with an oil price of 81 €/bbl (118 \$/bbl). In the past years oil prices already exceeded this value (see Fig. 8).

Finally, results also indicate that higher CO_2 transport and storage prices have a limited effect (between 0.9 and 3.2 €/GJ for all scenarios) on production costs (see Fig. 13 for the *Current Situation* scenario). As expected, the highest values are found in the *Business as Usual* scenario, while the *Current Situation* and *Green* scenarios show the lowest values.

[7] The break-even production costs of crude oil based gasoline/diesel consist of the crude oil price, a refinery margin and a carbon tax. A 6.0 €/bbl refinery margin was used, based on 46.5 $\$_{2002}/m^3$ diesel [14]. A 6.0 €/bbl CO_2 carbon tax was used, assuming 15 €/t CO_2. The following properties were used: an oil density of 845 kg/m^3; an oil carbon emission of 0.4 t CO_2/bbl, assuming a carbon mass content of crude oil of around 80%; an oil energy density of 6.12 GJ/bbl; 0.159 m^3 per bbl; and a currency conversion rate of 1.23 $\$_{2002} = 1.47\ \$_{2008} = 1.00$ €$_{2008}$.

Table 7
Impact feedstock flexibility on capital costs compared to static design.

Starting feedstock Flexible towards	Flexibility degree (%)	EP Coal (%)	E/C Coal (%)	Coal EP (%)	Coal TOPS (%)	T/C Coal (%)	TOPS Coal (%)
X to Electricity	0	100	100	100	100	100	100
	50		112	103	100	106	
	100	125	114	105	101	107	116
X to FT-liquids	0	100	100	100	100	100	100
	50		113	103	100	106	
	100	127	115	104	100	106	116
X to Methanol	0	100	100	100	100	100	100
	50		111	103	100	106	
	100	124	114	105	101	106	115
X to Urea	0	100	100	100	100	100	100
	50		113	102	100	106	
	100	128	114	103	100	107	115

4.2. Variation of feedstock

Feedstock flexible IG-PG facilities have higher capital costs and slightly lower overall efficiencies compared to static IG-PG facilities. However, they can respond to fluctuations in feedstock prices. We investigated whether feedstock flexibility pays off. First, the increase in capital costs and the impact on production costs of having a feedstock flexible IG-PG facility instead of a static IG-PG facility is presented. Optimal economic returns in relation to feedstock choice were calculated for different biomass pellet, coal and CO_2 credit prices, taking into account the variation in electricity price. Finally, a weekly variation in biomass pellet and coal prices was simulated at different CO_2 credit prices to assess the impact of short-term price variation on the economic performance of feedstock flexible and static IG-PG facilities.

4.2.1. Case 2. Capital costs penalty

Production costs of IG-PG facilities with static production, but with three levels of feedstock flexibility (0%, 50% and 100%) were compared, providing insights into the penalty induced by incorporating this flexibility in an IG-PG facility. The relative increase in capital costs is given in Table 7 and the impact on production costs is given in Table 8. The results were calculated for the *Current Situation* scenario. However, as the scenarios do not impact capital costs, the found trends also apply for the other scenarios.

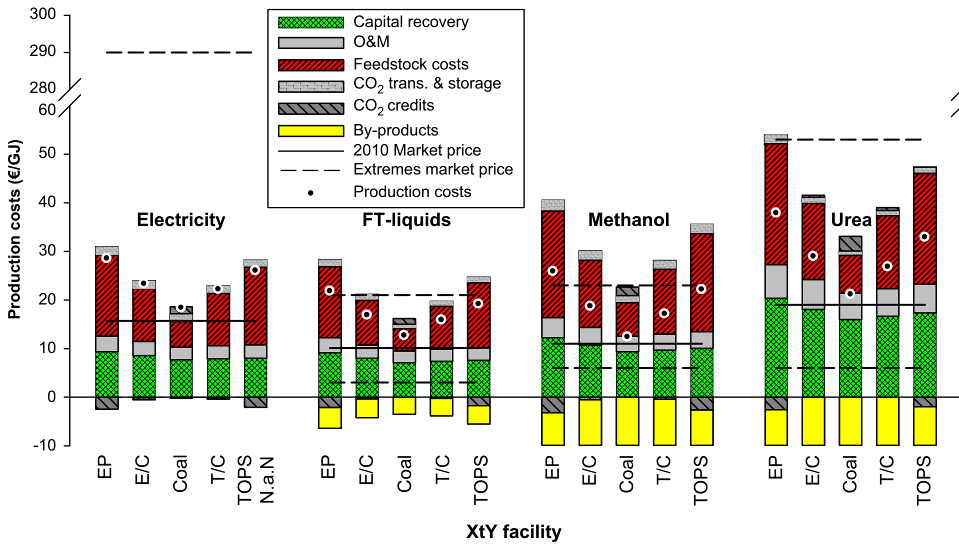

Fig. 13. Breakdown production cost of static IG-PG facilities under *Current Situation* scenario: 2.25 €/GJ coal; 6.3 €/GJ biomass pellet; 10 €/t CO_2 for transport and storage; 15 €/t CO_2 credit; 15.7 €/GJ co-produced electricity; 2000 MW_{th} coal eq. input; 4% O&M costs; 10% discount rate; 20 year lifetime. The dashed lines show the minimum and maximum market price of the produced commodity that occurred during 2000–2010.

Table 8
Impact on production costs of increased capital costs needed for feedstock flexibility under *Current Situation* scenario (€/GJ).[a]

Starting feedstock Flexible towards	Feedstock (X) Flexibility degree (%)	EP Coal	E/C Coal	Coal EP	Coal TOPS	T/C Coal	TOPS Coal
X to Electricity	0	28.5	23.3	18.4	18.4	22.2	26.0
	50		24.7	18.7	18.4	22.9	
(Market price = 15.7 €/GJ)	100	31.7	24.9	18.9	18.4	22.9	27.7
X to FT-liquids	0	21.8	16.9	12.7	12.7	15.9	19.2
	50		18.3	12.9	12.7	16.5	
(Market price = 10.1 €/GJ)	100	25.1	18.5	13.1	12.7	16.5	20.8
X to Methanol	0	25.9	18.7	12.4	12.4	17.1	22.2
	50		20.3	12.7	12.4	17.9	
(Market price = 11.0 €/GJ)	100	29.9	20.6	13.0	12.4	18.0	24.2
X to Urea	0	37.9	29.0	21.1	21.1	26.8	32.9
	50		32.1	21.6	21.2	28.3	
(Market price = 19.0 €/GJ)	100	45.4	32.4	21.8	21.2	28.3	36.4

[a] *Current Situation* scenario conditions: 2.25 €/GJ coal; 6.3 €/GJ biomass pellet; 10 €/t CO_2 for transport and storage; 15 €/t CO_2 credit;15.7 €/GJ co-generated electricity; 2000 MW_{th} coal eq. input; 4% O&M costs; 10% discount rate; 20 year lifetime.

Results indicate that an IG-PG facility designed as feedstock flexible, but operated as a static facility has production costs up to 20% higher compared to a static designed IG-PG facility. The increase in costs depends both on the used feedstock and desired production. The lowest penalty is obtained when making a coal based power plant (CtP) suitable for TOPS, while making an EP based urea (EtU) facility suitable for coal results in the highest penalty. The main reason for the added costs when re-designing a biomass based facility to be able to process coal is the need for larger Claus/SCOT and chemical conversion installations.

A major difference between EP and TOPS is the possibility to feed TOPS using the coal feeding system. EP is too fibrous and always requires a dedicated and different feeding system. This increases capital costs when constructing an IG-PG facility capable of processing both biomass and coal.

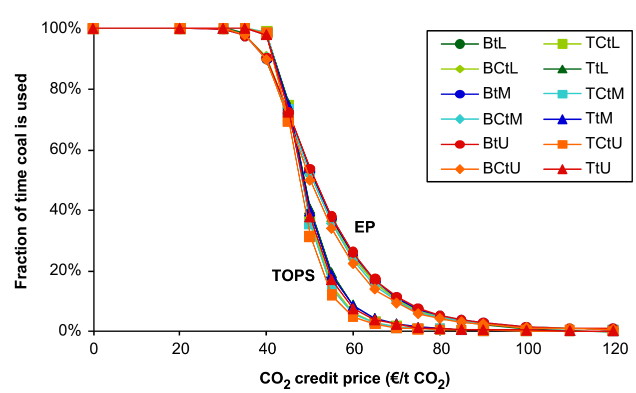

Fig. 14. Impact CO_2 credit price on feedstock preference under *Current Situation* scenario:. 6.3 €/GJ biomass pellets and 2.25 €/GJ coal.

4.2.2. Case 3. Constant chemical production and variable electricity production by feedstock substitution

A way to exploit the daily electricity variation is using different feedstocks depending on the electricity price. For this scenario it was assumed that switching between coal and biomass is instantaneously. In a previous study [20], it was found that the amount of gas generated in the EF gasifier must be kept constant. Due to differences in the heating value of biomass and coal, this

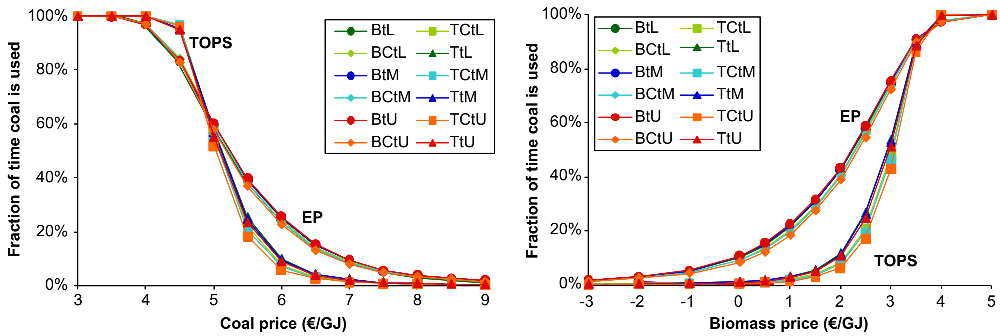

Fig. 15. Impact biomass pellet and coal prices on feedstock preference under *Current Situation* scenario:. 3 €/GJ biomass pellets (left), 2.25 €/GJ coal (right) and 15 €/t CO_2.

means that the energetic value of the syngas is highest when using coal and lowest when using EP. This effect can be used to operate an IG-PG facility as a mid-load[6] power plant. At low electricity prices, the facility will use biomass with maximal chemical production. When electricity prices increase, the feedstock is switched from biomass to coal, but chemical production is kept constant. The additional chemical energy in the syngas is used for extra electricity production. However, this principle is interesting only when feedstock prices per unit of energy, including CO_2 credit costs, are lower for biomass pellets than for coal. The *Current Situation* scenario has a low price for coal and CO_2 credits and a high price for biomass pellets. At these conditions, coal is more favourable than biomass pellets, regardless of the electricity price. However, with increasing CO_2 credit price, biomass pellets became more competitive with coal and eventually replaced coal (see Fig. 14).

EP becomes attractive at a CO_2 credit price lower than TOPS (30 €/t CO_2 compared to 40 €/t CO_2). However, full feedstock substitution is reached at a lower CO_2 credit price for TOPS (70 €/t CO_2) than for EP (100 €/t CO_2). For this analysis the electricity price was varied according to the Dutch day–hourly market prices between 2004 and 2008. If the electricity price is kept constant at 15.7 €/GJ, a sharp transition occurs around 54 €/t CO_2 for EP and 50 €/t CO_2 for TOPS, at which complete substitution of coal to biomass is observed.

The same effect of gradual substitution of coal by biomass is observed with increasing coal price or decreasing biomass pellet price. Analogous to the CO_2 credit price impact, EP begins replacing coal earlier than TOPS, but TOPS replaces coal faster and achieves complete substitution at lower coal prices or higher biomass pellet prices than EP (see Fig. 15).

Fig. 16 shows the relation between varying biomass pellet, coal and CO_2 credit prices for a flexible TOPS/coal to FT-liquids (XtL) facility with constant FT-liquids output. The base load electricity was sold for a fixed price (15.7 €/GJ) and the additional electricity was sold conform market spot prices. Biomass is the preferred feedstock in front of the two vertical planes, while coal is preferred behind them. Between the two planes feedstock preference is shared between biomass and coal, making this the space where feedstock flexibility is desired. The CO_2 credit price influenced the feedstock preference by tilting the planes, making biomass more economical at higher CO_2 credit prices. The difference between low and high biomass fractions is constant (2.2 €/GJ biomass pellet, 1.9 €/GJ coal and 22 €/t CO_2 respectively).

At 2010-market prices of 6.3 €/GJ biomass pellets, 2.25 €/GJ coal and 15 €/t CO_2, coal is the preferred feedstock. However, the historical data shows price variations between 5.7 and 7.3 €/GJ biomass pellet, 1.0–5.6 €/GJ coal and 0–32 €/t CO_2 (Figs. 4–6), represented by the dark blue box in Fig. 16. Although coal is still mostly the preferred feedstock within these ranges, within the

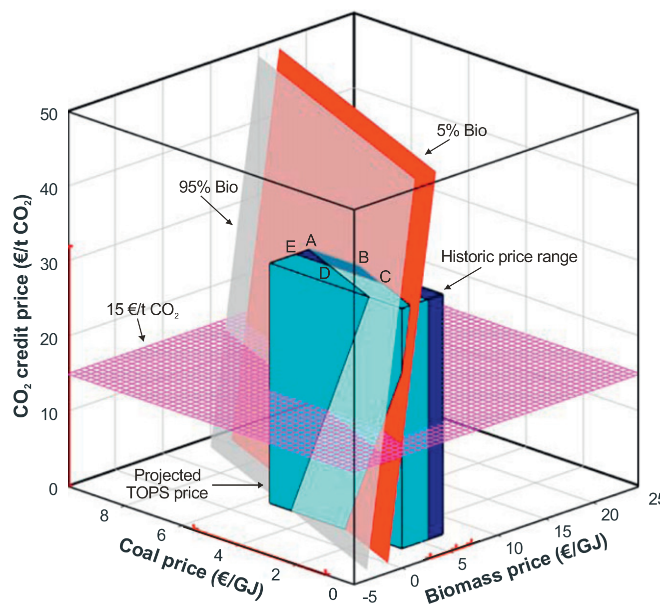

Fig. 16. Effect of biomass pellets, coal and CO_2 credit price on feedstock preference. The horizontal plane illustrates a CO_2 credit price of 15 €/t CO_2. In front of the light (grey) shaded vertical plane biomass is the preferred feedstock for more than 95% of the time, while behind the dark (red) shaded plane biomass is preferred less than 5% of the time. Between the two planes, both biomass and coal are preferred. Note that the dark blue block shows the price ranges that have occurred. The light blue block illustrates a drop in biomass pellet price to 3.0 €/GJ.

area ABCD[8] in Fig. 16, both biomass and coal are preferred and a feedstock flexible facility is desired.

The graph clearly shows that a higher CO_2 credit price allows the use of more expensive biomass. At 15 €/t CO_2 and 2.7 €/GJ coal, a price of 4.2 €/GJ TOPS results in a biomass preference of 95% of the time. If the CO_2 credit price increases to 30 €/t CO_2, the TOPS price can increase to 5.7 €/GJ TOPS, while still being the preferred feedstock for 95% of the time. At these conditions, FT-liquids can be produced for 15.8 €/GJ, equivalent to 116 $/bbl oil[7] if the oil is also taxed for 30 €/t CO_2.

4.2.3. *Case 4. Impact of short-term feedstock price variation*

Feedstock costs account for 23% (for coal) to 57% (for biomass) of total production costs under *Current Situation* scenario conditions. In this case study the effects of short-term variable feedstock prices on the economics of feedstock flexible IG-PG facilities were analysed. The flexible facilities adjusted, depending on the feedstock prices, their feedstock between either a 50/50 TOPS/

[8] Coordinates: A (7.3;5.6;32); B (7.3;3.9;32); C (5.7;2.6;32); D (5.7;4.4;32).

coal mixture and pure coal (semi-feedstock flexible), or between pure TOPS and pure coal (full feedstock flexible). Only TOPS was used for the analysis as the results from the previous case studies showed that TOPS based facilities have better economics than EP based facilities.

Based on the results of Case 3, four different CO_2 credit prices were examined. The reference price of 15 €/t CO_2; 40 €/t CO_2 reflected the value where TOPS is sometimes the preferred feedstock; 50 €/t CO_2 is the value where TOPS is the preferred feedstock for about 50% of the time; and at 65 €/t CO_2, TOPS is almost always the preferred feedstock (Fig. 14).

Results for the *Current Situation* scenario (Fig. 17) show that at a CO_2 credit price of 15 €/t CO_2, the economic performances of the static coal facilities are better than those of the feedstock flexible facilities. Increasing the CO_2 credit price reduces the NPV of both type of facilities. At higher CO_2 credit prices (40 €/t CO_2), the flexible facilities can, contrary to the static facility, switch their feedstock to TOPS. This reduces the decrease in NPV and, at even higher CO_2 credit prices ($>$50 €/t CO_2), improves the NPV of the flexible facilities. At a CO_2 credit price of 50 €/t CO_2, all three feedstock flexible facilities perform better than their static counterparts. The biomass share increases from almost zero at 15 €/t CO_2 to 25% at 40 €/t CO_2, 50% at 50 €/t CO_2, and reaches 85% at 65 €/t CO_2.

To determine the impact of changing TOPS and coal prices on the economics of IG-PG facilities, the same analysis was performed for the other scenarios. The biggest differences were observed under the *Green* and *Direct Action* scenarios (see Fig. 18).

The static facilities have a lower NPV in the *Green* scenario and a higher NPV in the *Direct Action* scenario. This is a direct consequence of the different coal prices. The flexible facilities show a different behaviour. At low CO_2 credit prices, coal is predominantly used. Therefore, the NPVs under the *Direct Action* scenario, with its lower coal prices, are better compared to those under the *Current Situation* and *Green* scenarios. With increasing CO_2 credit prices, TOPS is used more often. Therefore, the TOPS price becomes more important and the *Green* scenario has the best NPVs. This already happens at a CO_2 credit price of 40 €/t CO_2.

The prices of TOPS and coal also determine at which CO_2 credit price the switch is made from coal to TOPS. Over the lifetime of the facility, the *Green* scenario already has a 50% biomass share at

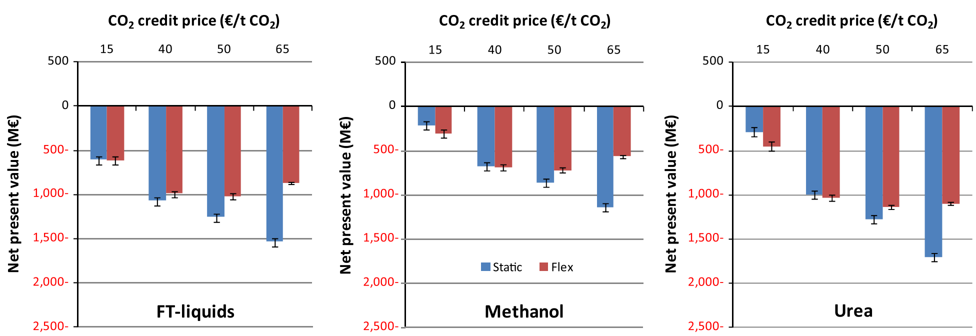

Fig. 17. NPV of static coal facilities (left columns) and full feedstock flexible TOPS/coal facilities (right columns) with constant chemical production under *Current Situation* scenario conditions: feedstock prices based on historic data; 10 €/t CO_2 for transport and storage; 15.7 €/GJ base load electricity; 10.1 €/GJ FT-liquids; 11.0 €/GJ methanol; 19.0 €/GJ urea; 2000 MW_{th} coal eq. input; 4% O&M costs; 10% discount rate; 20 year lifetime.

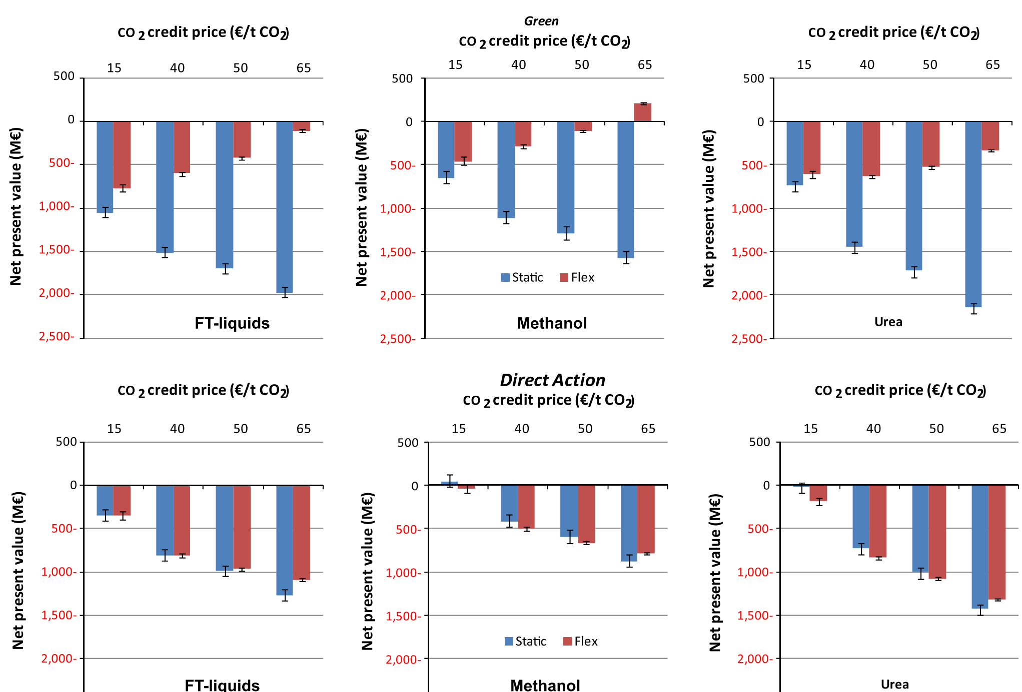

Fig. 18. NPV of static coal facility (left columns) and full feedstock flexible TOPS/coal facility (right columns) with constant chemical production. Upper figures used *Green* scenario conditions. Lower figures used *Direct Action* scenario conditions. Feedstock prices were varied based on historic data.

15 €/t CO_2. The *Current Situation* scenario needs a CO_2 credit price of 50 €/t CO_2 to reach this share, while the *Direct Action* scenario has a biomass share of only 30% at 65 €/t CO_2.

Another difference between the *Current Situation* and *Green* scenarios is when the NPV of the flexible facilities surpasses those of the static facilities. In the *Current Situation* scenario, this happens at a low CO_2 credit price ($\approx$ 15 €/t CO_2) for the static and feedstock flexible FT-liquids facilities. The methanol and urea facilities need a CO_2 credit price of 40 €/t CO_2. In the *Green* scenario, all flexible facilities have a better NPV than the static facilities, regardless of the CO_2 credit price. For the *Direct Action* scenario, only at a CO_2 credit price of 65 €/t CO_2 are the NPV of the flexible facilities better than those of the static facilities.

Also investigated was how often coal was replaced by biomass and vice versa. By keeping the feedstock substitution frequency as low as possible, the facility can be operated much smoother, resulting in, among others, reduced O&M costs and increased operating time. In the *Current Situation* scenario, the average substitution frequency reached a peak of 1.2 times a day at a CO_2 credit price of 50 €/t CO.

The simulations were also performed for the *Business as Usual*, *Direct Action*, and *Delayed Climate Policy* scenarios. Their results are in between those of the *Current Situation* and *Green* scenarios and are not shown here.

4.3. Variation of production

Besides exploiting the daily price variation of electricity by changing the feedstock, it is also possible to change production between chemicals/fuels and electricity. To minimise efficiency losses, both the power and chemical sections had a minimal load factor of 40%, resulting in only minor efficiency losses ($\Delta\eta < 1\%$) [20]. We investigated whether flexibility in production pays off. The NPV method was used to compare the economics of the static and production flexible facilities.

4.3.1. Case 5. Producing mainly chemicals/fuels during off-peak hours and mainly electricity during peak hours

In this case, the facility was used as a mid-load[6] power plant. Production was switched between chemical/fuel and electricity. A variable market price for the chemical/fuel was assumed using a Gauss distribution based on the historic mean and standard deviation. The electricity was sold according to the fluctuating Dutch day–hourly market prices. The feedstock, CO_2 credit and CO_2 transport and storage costs were based on the scenarios. The resulting NPVs over the lifetime of the facility for the *Current Situation* scenario are given in Fig. 19 left.

The flexible facilities have, to satisfy the 40% minimal load constraint, a smaller chemical section and a larger electricity section compared to the static facilities. This results for the FT-liquids facilities in an increase in capital and O&M costs (+1 to 2%) but also in an increase in fuel and electricity sales (+3%). The net effect is a higher NPV compared to the static facilities (ΔNPV = 138 M€ for coal to FT-liquids (CtL) and 92 M€ for TOPS to FT-liquids (TtL)). The methanol facilities show a similar behaviour, except that the increase in revenues is almost zero (+0%), while the capital costs increase by 3%–4%, resulting in a lower NPV for the flexible facilities (ΔNPV = −53 for coal to methanol (CtM) and −36 M€ for TOPS to methanol (TtM)). For the urea facilities it is the other way round. The capital costs decrease (−5%), but also the revenues from the urea and electricity (−8%), resulting in a lower NPV compared to the static facilities (ΔNPV = −159 for coal to urea (CtU) and −114 M€ for TOPS to urea (TtU)).

The CO_2 credit price has no influence on when to operate the flexible FT-liquids (XtL) and methanol (XtM) facilities as a power plant, as the sum of CO_2 emissions and carbon locked in the products remains constant, regardless production mode. As captured CO_2 is used for urea production, the amount of CO_2 emitted and stored by flexible urea facilities is dependent on the production mode and here a reduction in chemical production was observed at higher CO_2 credit prices. This is also the only influence of the different scenarios on the trends found in this case study.

Similar to Case 4, also investigated was how often the production mode was switched between chemical/fuel and electricity. The lower the switching frequency, the smoother the facility can be operated, resulting in, among others, reduced O&M costs and increased operating time. In the *Current Situation* scenario, the average switching frequency was 1.8 times a day for the methanol facilities, 1.7 times for the FT-liquids facilities and 1.1 times a day for the urea facilities.

The ability to adjust production made the flexible facilities less vulnerable to fluctuating market prices. The flexible facilities have a variation in NPV which is 40% smaller then the variation of the static facilities. For instance, the CtL facility has an uncertainty of 173 M€ for the static facility, but for the flexible facility this is only 100 M€. This holds for all cases, regardless the feedstock or production mix.

4.4. Case 6. Retrofit

We also analysed the impact of a retrofit during the lifetime of an IG-PG facility on the economic performance. The examined retrofit facility was a FT-liquids facility, producing FT-fuels for 20 years, which was then retrofitted to methanol production, producing methanol for another 10 years. The first step was to calculate the production costs of a static XtL facility operating for 30 years. This was the price at which the FT-liquids of the retrofit facility were sold. Next, the methanol production costs of the retrofit

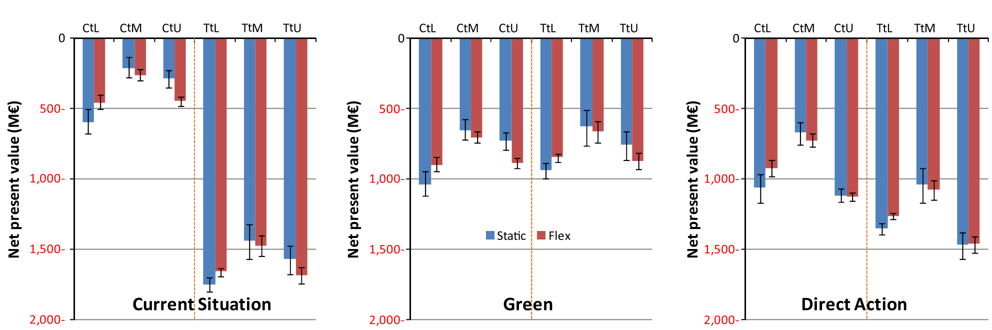

Fig. 19. NPV of static and production flexible TOPS/coal facilities under *Current Situation* (left), *Green* (middle) and *Direct Action* (right) scenario. Chemical/fuel prices were varied based on historic data. Electricity prices were based on the day–hourly spot market. Other commodity prices were based on the historic data and scenarios.

Table 9
Production costs (€/GJ) of static IG-PG facilities operating 30 years under the *Current Situation* scenario.[a]

IG-PG facility	Product	EP	EP/Coal	Coal	TOPS/Coal	Coal
XtL facility	FT-fuels	20.9	16.1	12.0	15.2	18.4
XtM facility	MeOH	22.7	16.1	10.2	14.8	19.6
Retrofit facility	MeOH	25.6	18.7	12.7	17.5	22.3

[a] *Current Situation* scenario conditions: 1.5 €/GJ coal; 6.7 €/GJ biomass pellet; 10 €/t CO_2 for transport and storage; 15.7 €/GJ co-generated electricity; 2000 MW_{th} coal eq. input; 4% O&M costs; 10% discount rate.

Table 10
Input sensitivity analysis.

Parameter	Unit	Normal	Range
Capital costs[a]	%	100	50%–150%
Discount rate	%	10	5%–15%
CO_2 credit price	€/t CO_2	15	0–100
Coal price[b]	€/GJ	1.5	1.0–5.6
Biomass pellet price[c]	€/GJ	6.7	3.0–7.3
Electricity price[d]	€/GJ	15.7	0–78.7

[a] The specific capital costs of the three main sources used for capital costs data varies between 76% and 120%. A slightly larger range was used due to the volatility and uncertainty of capital costs data.
[b] In the past years, coal prices varied between 25 and 140 €/t, or 1.0–5.6 €/GJ. The upper range is extended to 6.7 €/GJ to see the effect of a coal price which is similar to the biomass pellet price.
[c] In the past years, biomass pellet prices varied between 109 and 139 €/t, or 5.7–7.3 €/GJ. Several studies point out that biomass pellet prices may drop to 3.0 €/GJ in the future, due to e.g., technical learning, development of the market and introducing best practice agriculture [30–32].
[d] In the past years, the Dutch day–hourly market price of electricity varied between 0.01 and 292 €/GJ. An upper limit of five times the current electricity price was taken.

facility were calculated to obtain an NPV of zero. These production costs were compared to the production costs of a static XtM facility operating for 30 years. For the analysis, it was assumed that the retrofit was instantaneously and that excess equipment was sold for 5% of their original value. This analysis was done only for the *Current Situation* scenario.

Because the newly installed equipment for methanol synthesis was depreciated over 10 years only, instead of the 30 years for the XtM facility, this leads to an increase in methanol production costs of around 2.7 €/GJ ($\approx$ 60 €/t MeOH) as can been seen in Table 9. Such an increase in methanol market price occurred several times between 2000 and 2009, where 13% of the time the methanol market prices were at least 2.7 €/GJ above the average market price, all of which occurred in the period 2005–2010. Therefore, depending on product price development, such retrofits of IG-PG facilities can be attractive.

4.5. Sensitivity analysis

A sensitivity analysis was performed on a coal to FT-liquids, a TOPS to FT-liquids, and a feedstock flexible TOPS/coal to FT-liquids facility. The latter facility could switch feedstock between pure coal and pure TOPS and had a constant chemical production. For the sensitivity analysis, the *Current Situation* scenario was used. The varied parameters and their ranges are given in Table 10. The assumptions and uncertainties regarding the technical model of IG-PG facilities, e.g., gasifier limitation, fixed H_2:CO ratio and model validation, are discussed in Meerman et al., and are not discussed here [20]. Due to the different feedstocks and operation mode, the amount of FT-liquids produced differed per facility. The static coal-fired facility produced 28 PJ_{HHV} FT-liquids per year, while the static TOPS-fired and flexible TOPS/coal-fired facilities produced 23 PJ_{HHV} FT-liquids per year.

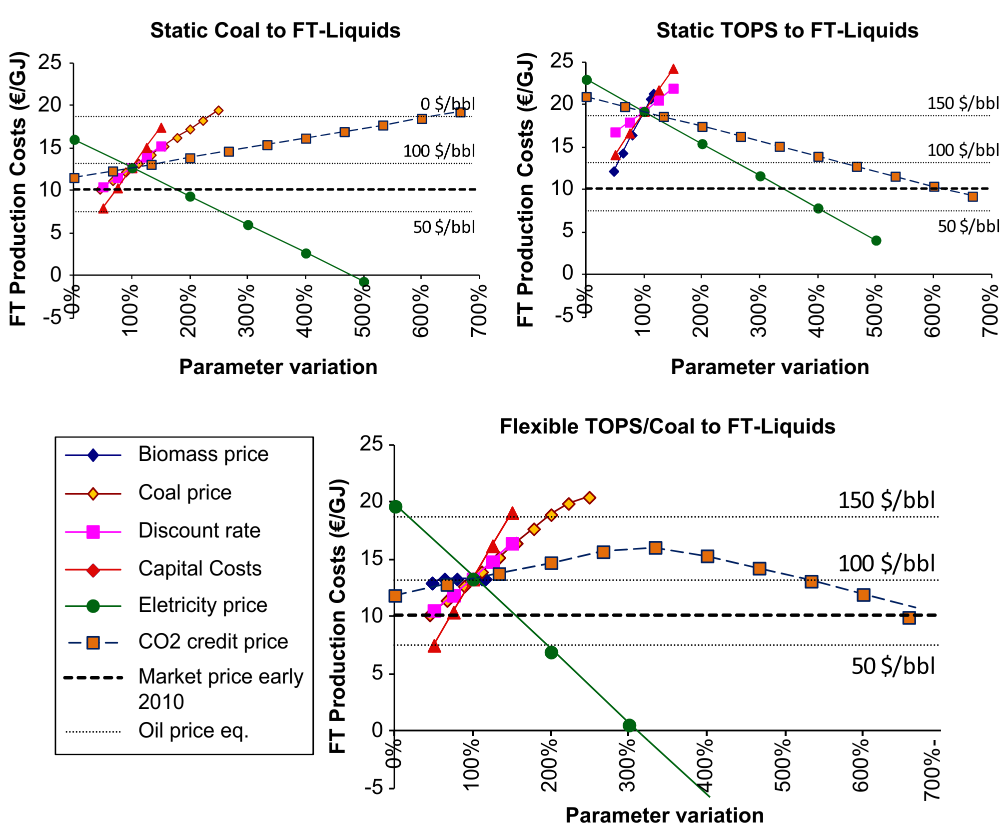

Fig. 20. Sensitivity analysis of static coal (upper left), static TOPS (upper right) and feedstock flexible TOPS/coal (bottom) to FT facility.

Results (Fig. 20) show that in all three cases, production costs of the FT-liquids are very sensitive to the capital costs. The electricity price also has a large impact, especially for the flexible facility. This was expected as the flexible facility produces much more electricity than the static facilities.

The feedstock prices show a linear relation with the production cost for the static facilities. This does not apply for the flexible facility. A lower biomass pellet price has, at first, almost no effect on FT-liquids production costs as it is still more profitable to use almost only coal. Only at low biomass pellet prices it becomes profitable to use biomass. At that point (<4 €/GJ biomass pellet), FT-liquids production cost starts to decrease. For the coal prices the opposite holds. When the coal price increases, coal initially remains the most economical feedstock, resulting in increasing production costs. Only at higher coal prices does biomass becomes more economical. At that point (>4.5 €/GJ coal), the increase in production costs slows down, until only biomass is used, at which point (>7 €/GJ coal) production costs remains constant.

As expected, CO_2 credit price has a strong increasing effects on FT-liquids production cost when using coal ($+0.8$ €/GJ per 10 €/t CO_2) and a decreasing effect when using TOPS (-1.2 €/GJ per 10 €/t CO_2). Production cost of the flexible facility initially increases with higher CO_2 credit price, but above 50 €/t CO_2, production costs drop again as biomass replaces coal as the preferred feedstock.

5. Discussion and conclusions

This study focuses on the economic implications of flexible operation of state-of-the-art gasification facilities, thereby complementing the technical assessment performed in Part A of this analysis. The main advantage of flexible IG-PG facilities over their static counterparts is their ability to react to variations in commodity prices and thus to maximise profits. Historical data clearly show strong fluctuations in the commodity prices. It is expected that these fluctuations will continue in the future and may become even more extreme due to increasing mismatches between supply and demand. Designing a coal-fired facility also allowing the processing of TOPS would increase capital costs by 0.5%. The combination of small additional investments and high uncertainty in commodity prices makes flexible IG-PG facilities attractive. Replacing coal for biomass, even when it results in lower electricity production, becomes attractive when the CO_2 credit price exceeds 40 €/t CO_2, the coal price exceeds 4 €/GJ or the biomass pellet price is below 4 €/GJ. In the last decade, coal prices have already exceeded this price. Furthermore, if changing market conditions are insufficient to make flexible IG-PG facilities more economical than their static counterparts, the ability of the flexible facilities to function as mid-load power plant may justify their deployment as they could prevent the construction of dedicated mid-load power plants.

Recently, a few studies assessing the techno-economic performance of gasification facilities have become available. These studies indicate that electricity could be produced from a gasification facility equipped with CCS for 18–21 €/GJ [47,48] if coal is used and for 37 €/GJ [48] if biomass is used as feedstock. In this study, these production costs were determined at 18 and 29 €/GJ respectively. The higher production costs of converting biomass to electricity in the NETL study is most likely a result of the assumed relative small scale of the facility. The literature studies also indicate FT-liquids can be produced for 8–9 €/GJ [49,50] if coal is used and for 19 €/GJ [50] if biomass is used. In this study, production costs of respectively 13 and 22 €/GJ were found. The lower feedstock prices used in these literature studies (1.0–1.6 €/GJ for coal and 3.5 €/GJ for biomass vs. 2.25 €/GJ for coal and 6.3 €/GJ for biomass used in this study) are the main reason of the lower production costs.

Static IG-PG facilities have production costs between 12 €/GJ (coal to methanol) and 38 €/GJ (EP to urea) under *Current Situation* scenario conditions. Using coal results in the lowest production costs, while the use of EP results in the highest production costs. This is mainly due to lower feedstock costs and higher product output related to coal. None of the static facilities have production costs under the market value of the products. When looking at the biomass fired facilities, the lowest production costs are under the *Green* scenario, mainly due to the lower biomass pellet price. The *Direct Action* scenario also has relatively low production costs as here the increase in CO_2 credit price offsets the increase in biomass pellet price.

At the current prices of 2.25 €/GJ coal, 6.3 €/GJ TOPS and 15 €/t CO_2, FT-liquids can be produced for 13 €/GJ from coal, equivalent to 96 $/bbl, and 19 €/GJ from TOPS, equivalent to 155 $/bbl. To match the profitability of a coal based FT-liquids facility, TOPS prices need to drop to about 3.3 €/GJ. However, when comparing the profitability with oil-based gasoline/diesel, the break-even point at an oil price of 144 $/bbl – 2008's peak – is already reached at 5.7 €/GJ TOPS.

The share of the capital costs on the production costs of static IG-PG facilities is 28–38% if biomass is used and 41%–48% if coal is used. If a coal-fired facility is designed to also process EP, capital costs increase by 3%–5%, which is higher than the 0.5% estimated for TOPS. The main reason for this difference is that TOPS can use the existing coal feeding system, while EP requires a dedicated feeding system. In the IG-PG facilities, the gasifier is the most capital intensive equipment, except for the urea facilities, where the urea section is the most capital intensive. As the capital costs make up a large share of the production costs, IG-PG facilities are very sensitive to changes in capital costs. To make static coal based facilities profitable, capital costs need to drop by 10%–27%. These values are within the uncertainty of the used method. However, this drop may also be obtained by technological learning [51]. For biomass, the required reductions in capital costs are 60%–96%. This is well above the methodological uncertainty and to make biomass based facilities profitable will, in addition to cost reductions due to learning, most likely also require lower biomass pellet prices or higher CO_2 credit prices.

The large difference in production costs when comparing coal-fired facilities with biomass-fired facilities is mainly the feedstock price. Under the market conditions of early 2010, feedstock prices account for 23%–30% of the production costs in coal-fired facilities, while in biomass-fired facilities feedstock prices account for 46%–57% of the production costs. A CO_2 credit price can be used to compensate this difference. The break-even CO_2 credit price for biomass pellets and coal for static facilities was calculated at around 50 €/t CO_2 for TOPS and 55 €/t CO_2 for EP. When looking at feedstock flexible facilities and considering the fluctuations in electricity price, biomass pellets are sometimes already the most preferable option at a CO_2 credit price of around 40 €/t CO_2. At a CO_2 credit price above 60 €/t CO_2 biomass pellets are calculated to be almost always the preferred feedstock.

The biomass pellet prices used in this study reflect current market prices. However, several studies indicate that technological learning, mature markets and local pre-treatment could drop biomass pellet prices considerably, e.g., to 3–4 €/GJ in the medium term. [30–33] At this price, coal is the favoured feedstock for about 50% of the time. At a CO_2 credit price of 30 €/t CO_2 for TOPS and 50 €/t CO_2 for EP biomass will replace coal almost completely as the preferred feedstock.

This study indicates that CO_2 capture and storage adds 2.8–6.4 €/GJ to the production costs: 1.3–3.3 € €/GJ for capture,

0.5–1.4 €/GJ for compression and 0.9–2.1 €/GJ for transport and storage. As CO_2 capture is mandatory for chemical production, the CO_2 compression, transport and storage costs are already offset by a CO_2 credit price of 15 €/t CO_2. It should be noted, however, that a CO_2 transport and storage costs of 10 €/t CO_2 was assumed. The actual costs could be higher depending on, for instance, reservoir availability and characteristics, pipeline availability and distance between IG-PG facility and reservoir site [52].

Changing market conditions have a large impact on the economics of IG-PG facilities. With the current market conditions, a production flexible FT-liquids facility is already more profitable than its static counterpart by exploiting the hourly variation in electricity price. For facilities which are feedstock flexible, the CO_2 credit price needs to increase to above 40 €/t CO_2 before flexibility pays off. The economics of the flexible facilities depend heavily on the feedstock and CO_2 credit prices. The larger these prices vary, the better flexible facilities perform compared to static facilities. In this scenario it was assumed that switching between coal and biomass is simultaneously. Although this is technically possible, the facility must be designed for it by, for instance, having separate feeding trains for the coal and biomass [53].

Finally, the results indicate that retrofitting an IG-PG facility producing FT-liquids towards methanol production increases methanol production costs by around 2.7 €/GJ compared to an IG-PG facility that continuously produces methanol. However, if the dominant transportation fuel switches from gasoline and diesel to methanol, the methanol market price could well rise above this value.

It should be noted that innovative processes that increase overall efficiency and decrease capital costs of the facilities are currently being developed, like membrane processes, hot gas cleaning and fuel cells [51,54,55]. Further research is required to determine how these processes may affect plant economics of both static and flexible IG-PG facilities.

The technical analysis, performed in part A, showed that flexible IG-PG can technically operate as mid-load power plants [20]. Integrating these facilities to the national power grid could result in added benefits. The extent of these benefits requires further research.

Acknowledgement

This research is part of the CAPTECH programme, which is a cooperation between the Dutch Ministry of Economic Affairs (EOS-LT programme) and its consortium partners: Energy research Centre of the Netherlands (ECN); KEMA Nederland B.V.; Procede; Shell Global Solutions International B.V.; TNO Science and Industry; Utrecht Centre for Energy research (UCE); and Utrecht University (UU). For more information: www.co2-captech.nl.

Appendix A. Supplementary material

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.rser.2012.06.030.

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